0000068366

EXHIBITS

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PART 5 OF 5
BAR CODE # 0000068366

To review remaining parts please see the following:

PART 1 OF 5 BAR CODED #0000068370

PART 2 OF 5 BAR CODED #0000068363

PART 3 OF 5 BAR CODED #0000068364

PART 4 OF 5 BAR CODED #0000068365

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rejoinder Testimony of

Thomas N. Hansen

on Behalf of

UNS Electric, Inc.

August 31, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Thomas N. Hansen.

Q. Are you the same Thomas N. Hansen who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to Mr. Magruder's Surrebuttal Testimony regarding the Renewable Energy Program.

II. UNS ELECTRIC RENEWABLE ENERGY PROGRAMS.

Q. Do you agree with the Surrebuttal Testimony of Mr. Magruder in his Part VII – Issue 5, Environmental Portfolio Standard ("EPS") and Renewable Energy Standard and Tariff ("REST") Surcharges?

A. No. While Mr. Magruder did recognize and correct many inaccuracies in his testimony, he did not provide any additional information in his Surrebuttal Testimony to challenge or change the statements made in my Rebuttal Testimony. For example, while the Magruder Surrebuttal Testimony discusses ISO 14400 certification and adds ISO 9000 certification to the discussion, there is still no evidence or example provided to create a link between such certifications and improved environmental compliance for electric utilities. In the remainder of my Rejoinder Testimony I will respond to specific points raised by Mr. Magruder, including:

- The structural insufficiency of funding for the EPS included in the EPS rule;

- Mr. Magruder's revised Table 14;
- Mr. Magruder's apparent misunderstanding of the UNS Electric's SunShare program approved by the Commission on December 21, 2006;
- Mr. Magruder's four final REST recommendations.

Q. Has the structural program design insufficiency of EPS funding been the primary cause of failure of any Arizona utility to meet the EPS requirements?

A. Absolutely. During the EPS rulemaking process, many parties provided testimony that the EPS surcharge was very likely insufficient to generate the revenues needed for meeting the EPS annual solar energy requirements, given the relatively high initial cost of solar generation. The Commission recognized this structural program design flaw and in response, Decision No. 63364 on page 4 at lines 18 through 20 states "It is not the Commission's intent that the ratepayers of Arizona pay the surcharge and also be faced with high deferred costs if it turns out the surcharge is not sufficient to allow an utility that is taking prudent measures to meet the portfolio percentage." Thus, utilities were allowed to only spend the EPS surcharge funds towards meeting compliance with EPS goals. If shareholder funds were to be spent towards EPS compliance, they could not be recovered through future rates. Additionally, the surcharge caps in the EPS rule were set as maximums which could not be increased, even by the Commission. See Decision No. 63364 at page 13, lines 26 and 27. Two utilities, APS and TEP were allowed to use existing DSM program funding in their EPS programs. This nearly doubled the amount of funds available. Even so, the funding was still not sufficient to meet EPS goals for those two utilities. UNS Electric has not had the benefit of any additional funding source and has been consistently dismayed, not excited as Mr. Magruder opines, that it has not been able to meet the EPS annual renewable energy goals. But given the limited funding that could be spent on the EPS program, the funds did not allow the goals to be met. This was recognized unanimously by the EPS Cost Evaluation Working Group in its report entitled

"Costs, Benefits, and Impacts of the Arizona Environmental Portfolio Standard" submitted on June 30th, 2003. Specifically, the Executive Summary at page 2 of that report states: "However, given the limited revenues available under the EPS rule, no utilities will be able to meet the annual renewable energy targets established by the EPS on the existing timeline."

Clearly, this statement shows that the EPS had a structural program design funding flaw, which did not provide sufficient funding for the solar generation portion of the EPS goals to be met. UNS Electric has met all of its EPS non-solar goals in every year of the EPS program for which UNS Electric filed the annual report. Yet, Mr. Magruder continues to beat the dead horse of UNS Electric being noncompliant with the EPS solar goals, without regard to the structural program design funding flaw in the EPS that resulted in inadequate EPS program funding. No utility has ever met the EPS annual solar energy requirements. Mr. Magruder fails to note any of these facts in his testimony.

Q. Is the revised Table 14 Mr. Magruder provided in his Surrebuttal Testimony a valid reflection of the status of UNS Electric compliance with the EPS?

A. Not at all. The revised Table 14 does not reflect: a) that not all EPS energy was to be from solar resources, and b) that multiplying factors were an essential part of the EPS program formula. Thus, the revised Table 14 has no more bearing on EPS compliance than the original Table 14. Any comparisons drawn between Table 14 and EPS compliance are inherently invalid. Moreover, my objections to the use of Table 14, even as revised, are not resolved.

Q. Is there any significant difference between the current UNS Electric and TEP SunShare program offerings that would support increased interest by UNS Electric residential customers in the first six months of 2007?

A. No. UNS Electric's residential SunShare program approved by the Commission on December 21, 2006 is effectively identical to the Option 3 residential program offered by TEP, and only marginally different from UNS Electric's SunShare program offered prior to December 21, 2006. The increased per capita interest in the UNS Electric program in the first six months of 2007 is a result of the increase in incentive rates offered in 2007. Other changes made to UNS Electric's SunShare program in December 2006, including the increase in the incentive rates and minor revisions to equipment qualifications are identical to the Option 3 residential TEP incentive rates and equipment qualifications revisions made in November of 2006. UNS Electric has supported and continues to support its SunShare program to its customers to the extent that EPS annual SunShare expenditure limits have nearly been reached already in 2007. To spend additional funds to provide outreach support to a program that has nearly exceeded its spending cap in mid year, would not be cost effective or prudent. We do appreciate Mr. Magruder recognizing that UNS Electric has administered its EPS program in a most cost effective manner to maximize the funds available for customer incentives.

Q. Would you please respond to the four recommendations made by Mr. Magruder in his Surrebuttal Testimony?

A. Certainly.

- *Magruder Recommendation #1: That [UNS Electric] continue to invigorate its "SunShare" program, as upgraded on 21 December 2006 and as expanded in its REST Implementation Plan expected filing during September 2007.* UNS Electric looks forward to Commission approval of its REST Implementation Plan.

- *Magruder Recommendation #2: That [UNS Electric] present in its REST Implementation Plan details on how it will transition from EPS to REST, as required by the ACC Decision No. 69127 and its rules in Appendix A of this Decision to comply with or exceed all REST requirements, summarized in Table 15 or as presented by [UNS Electric] to the Commission in its REST Implementation Plan.* While UNS Electric does not accept Mr. Magruder's Table 15 as the definitive REST compliance annual energy requirement definition, UNS Electric plans to file an REST Implementation Plan for Commission approval.

- *Magruder Recommendation #3: That [UNS Electric] present its REST Tariff not later than 14 October 2007 and implemented as required by the resultant Commission Order or Decision.* Since October 14, 2007, is a Sunday, UNS Electric shall present its REST Tariff on or before October 12th for consideration and approval by the Commission. UNS Electric shall not implement the REST Tariff prior to such an approval order of the Commission.

- *Magruder Recommendation #4: That all future ACC REST Reports be routed through and signed by Mr. Hansen, whose job title reflects this area, before submission to the ACC and Docket Control.* I have reviewed past UNS Electric EPS reports before submission to the Commission. We expect to continue that practice while I enjoy my current position responsibilities.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rebuttal Testimony of

Denise Smith

on Behalf of

UNS Electric, Inc.

August 14, 2007

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I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. What is your employment position?

A. I am the Director of Conservation and Renewable Programs at Tucson Electric Power Company ("TEP"), UNS Gas, Inc. ("UNS Gas") and UNS Electric, Inc ("UNS Electric" or the "Company"), collectively referred to as the "UniSource Energy Companies".

Q. Please describe your education and professional background.

A. I graduated from Northern Arizona University ("NAU") in 1991 earning a Bachelor of Science degree in Mathematics with an extended major in Statistics and then completed graduate work in Statistics at NAU. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix. After leaving NAU, I was hired by Pima Association of Governments in 1992 in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employee's travel to and from work.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In addition, I implemented and reported progress of existing DSM programs and then transitioned them into market-transformation programs. In 1999, I moved into the Pricing and Rates Department, developing cost of service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. I then accepted the position of Director of Conservation Services. Most recently my position was expanded to include

Renewable Programs. I manage the successful TEP Guarantee Home Program and, for the past year, have been researching and developing new DSM programs for all three UniSource Energy Companies.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Rebuttal Testimony is to respond to certain recommendations made by Mr. Marshall Magruder, RUCO and Commission Staff with regard to DSM matters.

Q. Did you file Direct Testimony in this proceeding?

A. No, I did not. However, due to my close involvement in the proposal, analysis, monitoring and reporting of DSM programs for UNS Electric, I was asked to respond to Intervenors' Direct Testimony regarding DSM matters.

Q. Please summarize your Rebuttal Testimony.

A. My Rebuttal Testimony focuses on Mr. Magruder's recommendations about the DSM programs themselves. For ease of review, my Rebuttal Testimony tracks Mr. Magruder's Direct Testimony on these issues. There are several areas where Mr. Magruder is incorrect and inaccurate, while also contradicting what Staff recommended in its DSM Report issued February 7, 2005 in Docket No. E-00000-02-0051 (hereinafter "Staff DSM Report").

In general, UNS Electric agrees with Staff's and RUCO's recommendations about DSM. However, UNS Electric is requesting that a few of Staff's and RUCO's recommendations be modified. I discuss those requested modifications in more detail later in my Rebuttal Testimony.

II. DEMAND-SIDE MANAGEMENT.

A. Explanation of New DSM Portfolio Filing.

Q. Is UNS Electric asking for approval of DSM Programs in this docket?

A. No. UNS Electric was advised by Arizona Corporation Commission ("Commission") Staff during the UNS Gas Rate Case proceeding (Docket No. G-04204A-06-0463) to file for DSM Program Portfolio approval – and the specific program plans contained therein – in a separate docket. Consistent with that request, UNS Electric filed its DSM Program Portfolio on June 13, 2007 in Docket No. E-04204A-07-0365 ("UNS Electric DSM Docket"); that filing is incorporated herein by reference.

Q. If UNS Electric is not asking for approval of DSM Programs in this docket, why is DSM Rebuttal Testimony being filed?

A. UNS Electric is filing Rebuttal Testimony addressing DSM for two reasons: (1) to address issues raised in Mr. Magruder's Direct Testimony; and (2) to request approval of a DSM cost recovery mechanism in this rate case. UNS Electric incorporated its DSM Portfolio in this Docket to provide sufficient information for the Commission to make appropriate recommendations for DSM cost recovery. The actual DSM Program Portfolio and specific program plans will be approved, or modified, by the Commission in the UNS Electric DSM Docket.

Q. Have there been changes to the original DSM Programs filed with Mr. Thomas J. Ferry's Direct Testimony in this Docket?

A. Yes. As stated above, UNS Electric filed its comprehensive DSM Program Portfolio *to replace* the original filing on December 15, 2006. UNS Electric determined the replacement DSM Program Portfolio was necessary to prevent similar concerns as those addressed from Staff, as well as other Intervenors, in light of TEP's Motion to Amend

Decision No. 62103 (Docket No. E-01933-05-0650) (hereinafter referred to as the "62103 Amendment Proceeding") – as well as comments from Staff witness Ms. Julie McNeely-Kirwan during the UNS Gas Rate Case. In those cases, Staff requested more detailed program descriptions with a separate filing and requested that both TEP and UNS Gas explore more DSM Program options. So, UNS Electric is attempting to address both Staff requests through filing its DSM Program Portfolio in the UNS Electric DSM Docket.

Q. What information was included in UNS Electric's DSM Program Portfolio?

A. UNS Electric refined the previous program descriptions based on Staff's recommendations and the Company considered more program options for its DSM Portfolio. We updated the avoided costs numbers to be consistent for all UniSource Energy Companies' DSM evaluations. In addition, we added programs and provided greater detail in the documentation for the cost-benefit calculations. An analysis of the Low Income Weatherization ("LIW") Program was also completed to identify energy savings associated with measures installed through that Program. UNS Electric also updated the program descriptions with the information requested by Ms. McNeely-Kirwan in the UNS Gas Rate Case and Ms. Barbara Keene for Staff in the 62103 Amendment Proceeding and included information requested on the overall DSM portfolio.

Q. Can you explain the difference in programs filed during Mr. Ferry's Direct Testimony and programs filed on June 13, 2007 in the separate DSM Program Portfolio docket?

A. The programs identified in Mr. Ferry's Direct Testimony included:

1. Time-Of-Use
2. Direct Load Control
3. Low-Income Weatherization
4. Energy Smart Home Program

5. Shade Tree Program

6. Education and Outreach

The specific DSM program plans filed in the UNS Electric DSM Docket include:

1. Direct Load Control
2. Low-Income Weatherization
3. Energy Smart Home Program
4. Shade Tree Program
5. Education and Outreach
6. Residential HVAC
7. Commercial Facilities Efficiency Program

The major program components and changes are outlined below:

<u>Direct Load Control:</u> The Program Plan for Direct Load Control provides comprehensive program detail, cost-benefit analysis, and plans for marketing and evaluation. UNS Electric has decided to initially limit the type of control to thermostats with radio frequency control in the Lake Havasu area.

<u>Low-Income Weatherization</u>: The Program Plan for Low-Income Weatherization ("LIW") provides comprehensive program detail and we included a cost-benefit analysis. UNS Electric also agreed with Staff to move $20,000 for bill assistance out of the Low-Income Weatherization Program and into the proposed UNS Electric Warm Sprit Program as also agreed upon in the UNS Gas Rate Case.

<u>Energy Smart Home Program:</u> UNS Electric evaluated the benefits of EPA's Energy Star Home Program and decided to use these National Standards for the Energy Smart

Home Program. The Program Plan for Energy Smart Homes also provides comprehensive program detail, cost-benefit analysis and plans for marketing and evaluation.

Shade Tree Program: The Program Plan for the Shade Tree Program also provides comprehensive program detail, cost-benefit analysis and plans for marketing and evaluation.

Education and Outreach: The Program Plan for Education and Outreach ("E&O") is a market transformation program that provides comprehensive program detail about residential and commercial education, the on-line energy audit and academic education. It also has been updated to include education for the newly designed Time-of-Use ("TOU") Rate options. The TOU Program itself has been eliminated from the list of specific DSM Programs, even though it is an important part of UNS Electric's DSM strategy. As it is essentially a rate design issue, Mr. D. Bentley Erdwurm addresses TOU rates in his Direct and Rebuttal Testimonies.

Residential HVAC: This program was added to the DSM Program Portfolio to provide more DSM options to existing residential customers. The Residential HVAC program promotes the installation of high-efficiency air conditioning and heat pump systems in existing homes in UNSE's service region. For equipment replacements, the program promotes the selection of high-efficiency equipment that exceeds the federal minimum efficiency standard of 13 SEER and quality installation practices

Commercial Facilities Efficiency Program: This program was added to the DSM Program Portfolio to provide more DSM options to existing commercial customers. The Commercial Program encourages commercial customers to install high-efficiency lighting equipment and controls, HVAC equipment, and energy-efficient refrigeration system retrofits in their facilities. The program will encourage contractors to promote the program and provide turn-key installation services to customers, and will provide training and education through seminars and brochures.

B. <u>Response to Mr. Magruder's Direct Testimony.</u>

1. <u>Citizens Advisory Council.</u>

Q. Do you have any response to the comments by Mr. Magruder regarding the Citizens Advisory Council ("CAC"), which has, as one of its duties, to discuss DSM planning for the community?

A. The CAC was formed in 1999 as a result of Decision No. 61793 (June 29, 1999) but the list of issues brought before the CAC predominantly dealt with a second transmission line and reliability. None of the CAC membership ever questioned or chose to discuss DSM planning. Further, no member of the CAC has requested a meeting to discuss DSM planning issues – or any other issues for that matter – since 2002.

2. <u>Similar Comments Shown on Multiple DSM Programs.</u>

Q. In his Direct Testimony, Mr. Magruder refers to "UNSE lost revenue recovery". Is UNS Electric requesting lost revenue recovery from DSM programs?

A. No. The only reference to UNS Electric lost revenue recovery in program documents filed in UNS Electric's DSM Portfolio filing relates to the calculation of program cost effectiveness. Specifically, lost revenues are a necessary component in the calculation of the Ratepayer Impact Measure ("RIM") test. This test determines the impact on rates to all UNS Electric customers. While the Commission does not require this test, it is important for all parties to understand that a RIM result of less than one will put upward-pressure on rates. Thus UNS Electric chose to include the calculation in all DSM Programs.

Q. In his Direct Testimony, Mr. Magruder requests that the cost effectiveness of UNS Electric DSM Programs be recalculated using formulas included in his Direct Testimony. Do you agree?

A. No. The Benefit/Cost calculations that UNS Electric used meet the guidelines the Commission recommended and the methods outlined in the California Standard Practice Manual. UNS Electric believes this is the most accurate and consistent methodology to calculate cost effectiveness. If the Commission requests that UNS Electric use an alternate method for these calculations, UNS Electric will utilize at alternate method.

Q. In his Direct Testimony, Mr. Magruder requests that more items be included in the environmental benefits table (*e.g.*, potable water, ozone and mercury.) Do you have any comments?

A. Yes. Potable water has not been included in the UNS Electric environmental benefit table because UNS Electric has calculated the avoided capacity using a Simple-Cycle Turbine which requires minimal water consumption. In addition, utility electric generating units do not emit ozone. Furthermore, neither Santa Cruz County nor Mohave County currently exceed the National Ambient Air Quality Standard for Ozone, nor are they projected to do so in the foreseeable future. Similar to the case for potable water, mercury emission reductions are not included in the UNS Electric environmental benefit table because UNS Electric avoided capacity would be served by a Simple-Cycle Turbine which has no mercury emissions.

Q. Mr. Magruder states in his Direct Testimony that the line loss factor and rates used in benefit/cost calculations do not meet proposed values. Do you have any comments?

A. Yes. Proposed rate schedules are not yet approved by the Commission. Until UNS Electric receives Commission approval, proposed values are just that - proposed. UNS Electric believes it would be inappropriate to utilize other values until the Commission approves the proposed rate schedules. For line-loss factors UNS Electric also includes those reported to the Commission during most recent rate case.

Q. In his Direct Testimony, Mr. Magruder suggests that Marketing and Advertising dollars be eliminated from each program in the DSM Portfolio and be replaced by the general education dollars budgeted in the E&O Program. Do you agree?

A. No. Significant and direct marketing and advertising is necessary to increase participation for each individual program. Marketing and advertising costs for each program must also be included in the total program costs to calculate the cost tests for each program. There are separate budgets for each program in the DSM Portfolio and marketing costs must be accounted for accordingly. Individual Program budgets for Marketing and Advertising cover development and delivery of marketing messages for each program through a range of strategies including, but not limited to:

- Promotions on the UNS Electric website;
- Bill stuffers mailed to existing UNS Electric customers;
- Advertising in major newspapers and other selected print media in the UNS Electric service region;
- Providing information through UNS Electric's customer care center;
- Developing marketing pieces, including brochures and other collateral pieces, to promote the benefits of each program; and
- Assisting with responding to customer inquiries about the program.

Q. Throughout Mr. Magruder's Direct Testimony, he recommends the DSM adjustor be calculated by dividing the number of customers into the program budget for a per customer charge. Do you agree?

A. No. UNS Electric, Staff and RUCO all agree in this proceeding through their respective Direct Testimonies that the DSM adjustor be determined on a kWh basis.

3. <u>Education and Outreach.</u>

Q. Mr. Magruder describes on page 16 at lines 24 through 27 in his Direct Testimony, that the E&O Program provides all the external media exposures, training, and marketing support for all UNS Electric DSM Programs. Do you have response to his description?

A. Yes. There is very little chance that $170,000 can provide all external media exposures, training, and marketing support for all UNS Electric DSM Programs plus the general education described here. The E&O Program simply provides general energy efficiency education to raise awareness about energy use and opportunities for saving energy. Items included in the E&O Program are the annual summer cooling tips and winter heating tips, general energy efficiency and conservation campaign, and promotion of the on-line Energy Advisor to answer energy use questions. The budget for these items totals $54,000 for the media campaign plus $11,000 for the license fee for the on-line Energy Advisor. The E&O Program budget also includes academic education through various school programs for $15,000. UNS Electric will also develop education and out-reach regarding the benefits of TOU rates from the E&O budget. The first year budget to promote the benefits of TOU rates is $90,000. UNS Electric will incorporate messages or 'tags' on many of these general energy efficiency messages to announce individual DSM programs so that the E&O education campaigns compliment separate messages and campaigns for individual DSM programs. The E&O Program does not include Marketing and Advertising for *any* specific DSM Program.

Q. In his Direct Testimony on page 18 at item 3.2.e, Mr. Magruder states that "The ACC Staff's definition of types of Demand-Side Management Programs does not include EC programs, thus without change, this program might NOT be included as a DSM program." Do you agree?

A. No. When selecting the programs for the DSM Program Portfolio, UNS Electric relied on the DSM definition in the Staff DSM Report. I believe the E&O Program meets the current definition of Energy Efficiency as outlined in the Staff DSM Report at page 3:

> "Energy Efficiency is products, services, or **practices aimed at saving energy** in end-use application generally by substituting technically more advanced (compared to what is presently used in a specific situation) equipment or **practices to produce the same or an improved level of end-use service with less energy use."** **[emphasis added.]**

Ultimately, The Commission will make the final recommendation on the program inclusion.

Q. On page 20, lines 16 through 18 in his Direct Testimony, Mr. Magruder requests that UNS Electric "change the Staff's Draft DSM Report definition for the types of DSM Programs" to agree with his recommended definitions. Do you agree?

A. No. UNS Electric participated in workshops with Staff and other stake-holders to determine the proposed DSM Policy ultimately included in the Staff DSM Report. UNS Electric believes no further definition as suggested by Mr. Magruder in his Direct Testimony from pages 16 through 17 is necessary. Moreover, UNS Electric has no authority to modify the Staff-recommended definitions.

Q. In his Direct Testimony, Mr. Magruder makes recommendations regarding the Education and Outreach Program. Is UNS Electric open to considering any of his recommendations?

A. Yes. UNS Electric believes all activities described in the E&O Program were designed to meet the needs of UNS Electric customers and influence a change in behavior that results in energy or demand reduction. UNS Electric is either open to considering or are already offering some of the recommendations in Mr. Magruder's Direct Testimony. For instance, UNS Electric is already proceeding with:

- Availability of speakers to civic organizations upon request – in response to Mr. Magruder's recommendation in his Direct Testimony on page 18, item 3.2.f.1.b – as long as resources exist to fulfill the request;
- Development of quarterly eNewsletters with energy information included – in response to Mr. Magruder recommendation in his Direct Testimony on page 19, item 3.2.f.3; and
- Availability of telephone energy assistance is available to all ratepayers – in response to Mr. Magruder's recommendation in his Direct Testimony on page 19 at item 3.2.f.4 through the call center or Account Managers.

Another important note is that UNS Electric is unable to provide 15-minute interval data without use of AMI/AMR ("automated meter intelligence / automated meter reading"). Therefore, UNS Electric is not able to consider the recommendation in Mr. Magruder's Direct Testimony at this time – at Section 3.2, item 7 on page 20.

Q. On pages 18 through 20 in his Direct Testimony, Mr. Magruder makes recommendations on measurement and evaluation on the E&O Program. Do you have any comments?

A. Yes. UNS Electric currently tracks the number of on-line energy audits started by commercial and residential customers. The Company also tracks the number of schools and school children who attend energy presentations and receive learning kits, and it further tracks the presentations to civic and business presentations including the number of people in attendance. But it is difficult to determine kWh and kW savings from a possible 'behavior" modification, so cost effectiveness on education and outreach programs can be costly to evaluate and results can be misleading. UNS Electric is considering some additional monitoring and evaluation methods to determine if each marketing effort identified in the E&O Program has resulted in a positive impact to alter consumer behavior.

4. Direct Load Control ("DLC").

Q. On page 23 at item 3.3.e.2 of his Direct Testimony, Mr. Magruder seemingly compares UNS Electric's proposed DLC Program to a Florida Power and Light Company ("FPL") DLC Program. He further states that FPL "has a 15-minute OFF cycle not more than once every four hours." Do you have any comments regarding his comparison?

A. Yes. Mr. Magruder is incorrect. FPL cycle strategy is comparable to UNS Electric's proposed DLC Program in that FPL utilizes a 50% cycle strategy – not the 15 minutes once during every 4 hours that Mr. Magruder described.

FPL uses a 50% cycle strategy (15 minutes each half hour) over a maximum duration of 3 hours within any 24-hour period. UNS Electric has proposed a 50% cycle strategy over a maximum duration of 4 hours within any 24-hour period. The longer duration in the UNS

Electric proposed DLC program is necessary to extend the potential cycle time through hours when system peak is registered. During times of extreme demand the FPL program may actually exceed the 50% Off cycle. Inserted below is the actual text from the FPL website related to its DLC program. (the 'On Call Program'):

> *"For example, air conditioning and central heaters may be put on a 15-minute savings cycle or an extended savings cycle. The 15-minute option cycles appliances off for 15 minutes each half hour for up to a total of three hours."*

> *"* During times of extreme demand, cycle time may be extended to a maximum of 17.5 minutes. During power system emergencies (e.g. extreme weather conditions and capacity shortages as determined by FPL), the cycle schedule and duration of the interruption may be extended.'*
>
> (http://www.fpl.com/residential/savings/residential_on_call.shtml).

Q. Do you agree that the 50% cycle time should be reduced from two hours per four-hour cycle to 15 minutes per four-hour cycle as Mr. Magruder recommends on page 25 at item 3.3.f.3 of his Direct Testimony?

A. No. UNS Electric has evaluated the cost-effectiveness of the DLC program and remains committed to the 50% cycle strategy and the 4-hour duration to meet peak demand requirements as presented in the UNS Electric DSM Docket. The 50% cycle strategy is utilized by many utilities around the country including the very success FPL program cited by Mr. Magruder. As recognized on page 23 of Mr. Magruder's Direct Testimony at item 3.3.e.2, the reduction from 120 minutes to 15 minutes "off" cycle during the four-hour duration would result in an 87.5% reduction in the demand impact produced by each participant in the DSLC program (from 2.5 kW to 0.32125 kW) and would not meet the TRC test required by the Commission.

Q. On page 24 at item 3.3.e.5 of his Direct Testimony, Mr. Magruder again mentions the FPL DLC program, stating "... FPL avoided about $3 billion with a DR program installed and paid by FPL (not ratepayer) company expense." Do you have any comments?

A. Yes. Mr. Magruder is incorrect when he stated that ratepayers do not provide the funding the cost for the FPL DLC Program. UNS Electric contacted the Senior Load Management Field Technician for FPL's On-Call Program. UNS Electric was essentially advised that FPL's On-Call Program, like all other FPL energy-conservation-approved programs, have all been filed and approved by the Florida Public Service Commission ("FLSC") – to be recovered through its Energy Conservation Cost Recovery "ECCR" clause and that more information can be found on FPSC's website.

To verify that the ECCR is similar to the Company's proposed DSM Adjustor, UNS Electric conducted some additional research. The best description of the ECCR administered by the Florida Power Service Commission was found on the web site for Gulf Power Company: http://www.gulfpower.com/pricing/pdf/ecc.pdf.

Q. Do you agree that Cares-M customers required to have electric powered life-support equipment be excluded from participating in a DLC program as Mr. Magruder recommends on page 24 at item 3.3.f.1 of his Direct Testimony?

A. Yes.

Q. Do you agree with Mr. Magruder's recommendation to add more Demand Response or "DR" options mentioned on page 25 at items 3.3.f.4 a through e of his Direct Testimony?

A. UNS Electric is willing to consider only items proven to meet cost-effectiveness tests. Mr. Magruder provides no evidence that his recommendations are cost-effective under any test.

If the Commission wishes to expand the options, those options can be considered in the UNS Electric DSM Docket.

Q. On page 25 at item 3.3.f.4 of his Direct Testimony, Mr. Magruder requests that UNS Electric revise the DLC Participation Agreement. Do you have any comments?

A. Yes. UNS Electric is willing to consider revisions to the Draft Participation Agreement during the implementation phase after the DLC Program receives Commission approval for implementation.

Q. On page 25 at items 3.3.f.6 and 3.3.f.7 of his Direct Testimony, Mr. Magruder suggests 'incentives', 'bonus' and other changes to the Participant Agreement. Do you agree?

A. No. UNS Electric believes that providing the communicating thermostat to the customer will be enough incentive to encourage participation in the program. Any additional incentives or bonus would add unnecessary costs and may cause the program to fail benefit/cost analysis. If the Commission wishes for UNS Electric to include additional costs it would be considered during the separate proceedings to approve the DSM Program Portfolio.

Q. Do you agree with Mr. Magruder's recommendation that UNS Electric should use only "Off-the shelf, proven equipment and DLC hardware and software"?

A. No. DLC technologies are not mature and the range of DLC technology options available commercially today is a small fraction of those that will be available in the future. Because of the anticipated rapid expansion of improved DLC technologies in the future, UNS Electric is investigating a number of equipment options but has not chosen the equipment at this time. The option UNS is exploring would integrate DLC with the UNS strategy for AMI/AMR, thereby gaining efficiency from the equipment and communication structure.

It would also provide the necessary data to accurately calculate saving from a DLC customer plus increase customer satisfaction through more information on their energy use. If the Commission wishes to limit the options open to UNS Electric this would be considered during the separate hearings to approve the DSM Program Portfolio.

5. Low-Income Weatherization.

Q. On pages 28 at item 3.4.f.2 of his Direct Testimony, Mr. Magruder suggests eliminating $2,552 from the total budget. What is your response?

A. The $2,552 dollar entry was placed in the incorrect line of the detail budget. This dollar amount should relate to "Rebate Processing" and be distributed to the agencies to help cover the cost of this activity. Therefore, UNS Electric does not agree that the $2,552 should be removed from the total budget.

6. Energy Smart Home.

Q. On page 30 at items 3.5.e.1 and f.1 of his Direct Testimony, Mr. Magruder discusses reducing high recurring costs and improving the return to customers to 45% in 2009. Do you have any comments?

A. Yes. The calculation included in Mr. Magruder's Direct Testimony on page 30 is not accurate. The total Direct Implementation costs submitted for this program are $243,600, *not* $161,312 as stated in Mr. Magruder's testimony. Utilizing the actual direct costs for the program to calculate the return to customers, UNS Electric's return to customers is 58% in the first year (243,600/420,000).

Q. On page 30 at item 3.5.f. 2 of his Direct Testimony, Mr. Magruder suggests that annual goals for the Energy Smart Home should be increased. What is your response to his suggestion?

A. UNS Electric will make every attempt possible to increase the number of participants in the Energy Smart Home Program. UNS Electric would be thrilled to reach 42%, or higher, participation by 2012. But UNS Electric does not have ultimate control over how many residents decide to participate. For the purpose of planning, UNS Electric would rather be conservative in its estimates of participation. If program participation exceeds the estimated percentages in the Energy Smart Program Plan, UNS Electric will inform the Commission through UNS Electric's semi-annual DSM Report.

Q. On page 30 at item 3.5.e. 3 of his Direct Testimony, Mr. Magruder requests a sample Partner Agreement. Do you have any comments?

A. Yes. The partner agreement with Energy Star is an agreement between Energy Star and the Builder. UNS Electric does not develop this agreement, but it can be found on the Energy Star web-site (www.energystar.gov). Agreements between UNS Electric and the builder have not yet been developed but will be developed in the coming months.

7. <u>Residential HVAC Program.</u>

Q. In his Direct Testimony at item 3.6.f.1 on page 33, Mr. Magruder makes the recommendation to remove $35,952 of subcontractor expenses and $12,000 of internal marketing expenses from the total program budget. Do you agree with his recommendations?

A. No. Although UNS Electric may administer the program internally, subcontractors will be used for various items including program design and development, verification of equipment efficiency, inspections, rebate processing and data entry. If subcontractors do not complete these items, all the work would then be completed by UNS Electric employees. Mr. Magruder needs to understand that the detailed budgets have been placed in categories based on estimated allocations that are common to other utility DSM programs. Actual costs may vary among subcategories. Regarding the $12,000 of marketing costs, Mr. Magruder suggests be eliminated, those costs include payments to the HVAC Contractors, as outlined in the program description under Products and Services, at Attachment 5 page 4 of UNS Electric's DSM Program Portfolio filed June 13, 2007. As I discussed earlier in my Rebuttal Testimony, the E&O Program does not include marketing for specific programs. The recommended budget by UNS Electric must remain at the level UNS Electric proposes to ensure successful implementation.

Q. In his Direct Testimony at item 3.6.f.2 on page 33, Mr. Magruder questions 17 and 18 SEER incentives. Do you have any comments?

A. Yes. Mr. Magruder misunderstands the information UNS Electric included in its DSM Program Portfolio at Appendix 3. UNS Electric recognizes that some equipment with 17 and 18 SEER ratings are available, but the choices are not great and the cost is high. Appendix 3 is used to estimate the size and efficiency of equipment that would most likely be installed in this program. Because the likelihood of having any 17 to 18 SEER equipment installed is slim, the analysis shows a zero for that category. If the Commission wishes for UNS Electric to escalate rebates for 17 and 18 SEER equipment above the recommended $100/ton, it can be considered in the UNS Electric DSM Docket.

Q. In his Direct Testimony also at item 3.6.f.2 on page 33, Mr. Magruder suggests that savings in therms should be included for heat pumps. Do you have any comments?

A. Yes. UNS Electric followed the Staff DSM Report to determine the baseline equipment. In that Report on page 19 regarding Fuel Neutrality, it clearly states: "For those installations/applications that have multiple fuel choices, ***the baseline used in the cost***

effectiveness analysis shall utilize the same fuel source as the installation/application." [emphasis added] Therefore, UNS Electric followed this procedure in calculating program savings and assumed in the cost-benefit analysis a high-efficiency heap pump would replace an older heat pump.

8. <u>Shade Tree Program.</u>

Q. In his Direct Testimony at item 3.7.a on page 33, Mr. Magruder states that "UNS Electric does not have an assessment of the impact of reducing loads or energy savings potential through shading from trees." Is this true?

A. No. UNS Electric has estimated savings based on the calculation of energy savings on a detailed report compiled by Gregory McPherson and James R. Simpson, <u>Desert Southwest Community Tree Guide</u> – Benefits, Costs and Strategic Planting, 2004. UNS Electric also used the assessment from the same report that indicates no calculations of demand savings. UNS Electric's DSM Portfolio at Appendix 3 of Attachment 6 outlines the estimated energy savings.

Q. In his Direct Testimony at item 3.7.d on page 34, Mr. Magruder states that the program "has a repeated and not relevant section on Monitoring and Evaluation. It is not expected that UNS Electric field personnel will check customer's yards to verify UNS Electric "shade trees"." Do you agree?

A. No. The Monitoring and Evaluation section is repeated in several programs but is relevant. Because of the Measurement and Evaluation requirements recommended in the Staff DSM Report, UNS Electric will field-inspect installation of a statistical sample of trees installed through this Program. This was clearly stated in UNS Electric's DSM Portfolio on page 3 of Attachment 6: "**Field verification** – UNS Electric will conduct field verification of the installation of a sample of measures throughout the implementation of the program."

Q. On page 35 at item 3.7.f.1 of his Direct Testimony, Mr. Magruder recommends that the Commission not approve this program. Do you have any comments?

A. Yes. UNS Electric believes the Shade Tree Program provides significant energy and environmental benefits to customers. Whether the Shade Tree Program will be rejected based on the information provided by Mr. Magruder (3.7.e.1), however, is a matter for discussion by the Commission during the UNS Electric DSM Docket.

9. <u>Commercial Facilities Efficiency Program.</u>

Q. In his Direct Testimony at item 3.8.e.1 on page 38, Mr. Magruder assumes that all participants will receive the maximum of $10,000 and the customers allowed to participate will be limited to 28.5 customers. Do you have any comments?

A. Yes. UNS Electric believes that most customer rebates will be significantly lower than $10,000. UNS Electric added the incentive cap to prevent one or two customers from consuming the entire budget for the program.

Q. On page 38 at item 3.8.e.3 of his Direct Testimony, Mr. Magruder requests a sample of proposals, agreements and report formats. How do you respond to his requests?

A. Development of forms, agreements, and proposals has not yet been developed but will be in the coming months for Commission approval.

C. <u>Response to Staff Witness Jerry Anderson's Testimony.</u>

Q. Does UNS Electric agree with comments made by Mr. Anderson?

A. Yes. UNS Electric agrees with the Jerry Anderson's comments and recommendations in his Direct Testimony.

Q. Are there areas that UNS Electric agreed to modify regarding the Direct Testimony of Tom Ferry concerning its DSM Program?

A. Yes. UNS Electric has agreed to modify two major points in UNS Electric's DSM Portfolio Filing:

- UNS Electric recommended in its portfolio filing that the $20,000 allocated to the Emergency Bill Assistance component of the LIW be re-categorized into the proposed Warm Sprits Program and that it not be funded with DSM funds.
- UNS Electric recommended in its portfolio filing that UNS Electric's TOU pricing plans not be considered as DSM, and that these activities not be funded with DSM funds.

D. <u>Response to Ms. Marylee Diaz Cortez's Testimony.</u>

Q. Does UNS Electric agree with comments made by RUCO's witness Marylee Diaz Cortez?

A. Generally, yes. But I need to make one correction regarding her Direct Testimony on DSM Programs. Ms. Diaz Cortez indicated that the existing program budget was $460,000 annually; in fact, that figure is only $175,000 annually for existing DSM programs plus an additional $70,000 annually for LIW.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rejoinder Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

August 31, 2007

EXHIBIT
UNSE 29
Admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. Are you the same Denise Smith who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Rejoinder Testimony is filed on behalf of UNS Electric.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to certain comments Mr. Marshall Magruder makes in his Surrebuttal Testimony.

II. RESPONSE TO MR. MAGRUDER.

Q. How does UNS Electric respond to questions, comments, and allegations made by Mr. Magruder in his Surrebuttal Testimony regarding Demand-Side Management Programs?

A. While UNS Electric has agreed with Mr. Magruder on a few select specific items, the Company disagrees in general with Mr. Magruder's DSM recommendations and allegations. UNS Electric remains committed to its selection of DSM programs, the cost-benefit analysis, and the individual program designs in the DSM Portfolio Program filed on June 13, 2007. The Company's position with regard to Mr. Magruder's objections and recommendations are fully described in my Rebuttal testimony.

Q. On page 15 of Mr. Magruder's Surrebuttal Testimony he recommends a DSM integration plan to summarize goals and objectives and centralized cost accounting of DSM programs. Do you agree?

A. Yes. This information has been provided in the June 13th filing in Docket No. E-04204A-07-0365 and can be found in the DSM Portfolio Plan.

Q. On page 22 of his Surrebuttal Testimony, Mr. Magruder assumes that UNS Electric will implement and incorporate recommendations that UNS Electric did not specifically respond to in Rebuttal Testimony. Is that accurate?

A. No. Just because UNS Electric did not respond to each of the myriad of specific items in Mr. Magruder's Direct Testimony, Supplemental Direct Testimony, or Surrebuttal Testimony does not indicate that we agree with his recommendations.

Q. Mr. Magruder claims UNS Electric's DLC program includes "potentially life-threatening structural flaws." Do you agree?

A. No. First Mr. Magruder provides no reference or documentation to support his inflammatory allegation. Second, the UNS Electric DLC program is voluntary and provides for a customer override of a control event. Third, one advantage with the two-way communication is UNS Electric can build an individual thermal load profile for each home. Thus, any excessive temperature increase in an individual home can be mitigated.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-____

Direct Testimony of

Edmond A. Beck

on Behalf of

UNS Electric, Inc.

December 15, 2006

EXHIBIT
tabbies
UNSE 30
Admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Edmond A. Beck. My business address is Tucson Electric Power Company ("TEP"), P.O. Box 711, Tucson, Arizona 85702.

Q. What is your employment position?

A. I am the Superintendent of Planning and Contracts for TEP. In that capacity, I am responsible for TEP's transmission and distribution system planning, transmission system service requests and regulatory processes related to transmission. I also provide transmission and distribution planning support for UNS Electric, Inc. ("UNS Electric").

Q. Is your educational background and work experience summarized in Exhibit EAB-1 to your Direct Testimony

A. Yes, it is.

Q. On whose behalf are you filing your direct testimony in this proceeding?

A. My testimony is filed on behalf of UNS Electric.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to:

(i) discuss the current state of the reliability of electric service in UNS Electric's Santa Cruz County service area, including both transmission and generation facilities used to serve the area and identify the efforts that UNS Electric has taken to improve reliability in its Santa Cruz County service area;

(ii) explain why UNS Electric's capital investments, including the recent installation of a 20MW combustion turbine at the Valencia substation in Nogales, are necessary to maintain and improve the reliability of electric service to Santa Cruz County and should be included in rate base;

(iii) discuss the current state of the reliability of electric service in UNS Electric's Mohave County service area and the reliability benefits of constructing Company-owned generation within that service area's load pocket.

Q. Please summarize your testimony.

A. UNS Electric has closely analyzed its system to identify methods for maintaining and improving reliability. UNS Electric recently installed a new 20MW turbine in Nogales as a critical element for the reliability and restoration needs of Santa Cruz County. The turbine became commercially operable during the Test Year and we are seeking to include it in rate base. The Company also has undertaken other system improvements in the Santa Cruz County service area since the acquisition of the electric system assets from Citizens to improve reliability. With respect to UNS Electric's Mohave County service area, the addition of the Black Mountain Generating Station ("BMGS") will improve reliability in that load pocket and will help ameliorate transmission limitation concerns in the future.

II. RELIABLE ELECTRIC SERVICE IN SANTA CRUZ COUNTY.

A. Elements of Reliable Service.

Q. Mr. Beck, please explain what the term "reliable electric service" means.

A. UNS Electric focuses on providing safe, reliable and economical electric service to its customers. UNS Electric deems electric service to be "reliable" as customers continuously receive their electric requirements. UNS Electric strives to minimize interruptions in service. Important indicators of reliable electric service are (i) adequacy of service; and (ii) security of service.

Q. Please explain "adequacy of service".

A. Adequacy of service is a utility's ability to supply electric demand and energy requirements of customers at all times (taking into account scheduled and reasonably expected unscheduled outages of system elements).

Q. What is "security of service"?

A. Security of service is a utility's ability to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements in providing electric service. When analyzing security of service, it is important to focus on "continuity of service" and "restoration of service".

Q. Please explain "continuity of service".

A. Continuity of service means a utility's ability to provide, without unplanned interruption, electric service to a customer.

Q. Please explain "restoration of service".

A. Restoration of service means a utility's ability to return electric service to customers. When there is an outage a portion of the customers served by the system may lose their electric service. When the customers again have electric service available they are "restored" to service.

Q. How do these concepts factor into providing reliable service for Santa Cruz County?

A. UNS Electric carefully analyzes all of these various reliability-related elements in construction, operation and maintenance of its electric system in Santa Cruz County. These elements have also served as important criteria for UNS Electric's evaluation of reliability options to implement in the future. The electric facilities that UNS Electric will construct depend in large part on what will best ensure adequate and secure service.

Moreover, regularly scheduled maintenance will be planned to ensure that electricity will always be available to meet anticipated load, barring any unforeseen or unscheduled events. UNS Electric is committed to providing reliable electric service to its customers in the near term and in the long term.

B. Overview of Electric Service in Santa Cruz County.

Q. Mr. Beck, when did UNS Electric begin to provide electric service to Santa Cruz County?

A. UNS Electric began to serve Santa Cruz County in August 2003 upon acquisition of Citizens' Arizona electric systems.

Q. Mr. Beck, could you provide an overview of the Santa Cruz system immediately prior to UNS Electric's acquisition of the system from Citizens?

A. Prior to UNS Electric's acquisition of the system from Citizens, there were significant concerns about the reliability of electric service in Santa Cruz County. As a result of those concerns and a Commission proceeding, Staff and Citizens filed a Settlement Agreement in August 1999 that committed Citizens to a Plan of Action. The Settlement Agreement was subsequently approved by the Commission in Decision No. 62011 (November 2, 1999). Under the Plan of Action, Citizens had:

- Added a new system (sync-check relay) to synchronize Citizens generation units at Valencia Power Plant with Western Area Power Administration's ("WAPA") transmission system;
- Installed a new 115kV switching station at Nogales Tap Station to convert the interconnection between Citizens and WAPA from a simple tap to a three breaker ring bus;
- Replaced selected structures and components on the existing 115kV line;

- Pursued a second transmission source into the service area

Q. Please describe system improvements that UNS Electric has made in Santa Cruz County subsequent to acquisition of the system from Citizens.

A. UNS Electric undertook several key efforts shortly after the acquisition, including:

1. UNS Electric had TEP incorporate the three existing turbines located in Nogales into its Energy Management System in the TEP control room to allow remote control capability by TEP operators.
2. UNS Electric added a considerable quantity of capacitors into the Santa Cruz System to improve voltage levels and power factor. Each year UNS Electric reviews the need for additional capacitors to maintain the corrections.
3. TEP and UNS Electric also installed an emergency 46kV/115kV interconnection between TEP's Canoa and UNS Electric's Kantor Substation to improve restoration of service in Santa Cruz County. The connection is available as needed in response to an outage on UNS Electric's system.
4. TEP and UNS Electric also transferred operational control of the Santa Cruz system to TEP's control center in Tucson. TEP construction personnel are available to provide support in response to outages.
5. UNS Electric converted its Geographic Information to GE Smallworld to allow TEP operations to utilize its work management and power outage management system.

Many of these improvements help to harmonize UNS Electric's operations in Santa Cruz County with TEP's operations without having to jeopardize the two county restrictions. Further, these improvements help to restore service more quickly to Santa Cruz County when an outage occurs. Finally, the improvements have created efficiencies in the operation of the system.

Q. Please describe how UNS Electric presently provides electric power to Santa Cruz County.

A. UNS Electric obtains electric power for Santa Cruz County through a Power Supply Agreement ("PSA") with Pinnacle West Capital Corporation ("PWCC"). In general terms, PWCC provides full requirements energy and capacity for Santa Cruz County to UNS Electric at the Saguaro Generating Station near Red Rock, Arizona. UNS Electric has contracted with WAPA to transport the electric power (up to 65.8 MW) over its transmission lines to UNS Electric at the Nogales Tap located near Wilmot Road and Old Vail Road in Tucson, Arizona. UNS Electric then transports the electric power to Nogales (and other parts of Santa Cruz County) over the UNS Electric 115 kV radial transmission line. A map depicting the transmission lines is set forth in Exhibit EAB-2.

UNS Electric also owns four generators in the Santa Cruz County load pocket. The newest generator is an LM2500 turbine that was installed in 2006 for approximately $14 million. The other three turbines are 1970 vintage GE turbines that were originally installed in Japan. They were refurbished in the United States in 1989 and subsequently installed at the Valencia Substation in Nogales. The three older turbines have a combined output of approximately 47MW.

Q. Is the current arrangement for providing electric power to UNS Electric's customers in Santa Cruz County still susceptible to reliability problems?

A. Yes, it is susceptible to both adequacy and security problems. As discussed in more detail below, the Santa Cruz County service area is faced with limited transmission options into the area. This creates a load pocket that may not be able to import adequate electric power from outside the load pocket to meet the demand. As a result, UNS Electric must utilize local generation options to overcome contractual limits by its transmission provider as well as for restoration when the transmission source is unavailable. When the load in Santa

Cruz County exceeds 65.8 MW, the increment of load over this value is served via local generation in Nogales. If there is an outage of the 115kV line serving Santa Cruz County, then TEP and UNS Electric can energize the 46kV tie between TEP and UNS Electric and start-up turbines in Nogales in order to provide sufficient energy to meet the immediate load requirements.

Q. Please explain the potential adequacy problems in more detail.

A. Currently Santa Cruz County's weak link of service is the WAPA transmission system between the Saguaro Generating Station and the Nogales Tap. WAPA has limited UNS Electric to 65.8 MW of transmission capacity beginning June 2006 due to contractual limitations on their transmission system (they have contracted sales for all of their capacity with no additional firm point to point capacity available). Beginning in 2005, there was inadequate firm transmission capacity on WAPA's system needed to serve expected peaks in Santa Cruz County. Those peaks typically occur in the summer months. Given the time frame for the siting and construction of new transmission to the Nogales Tap and from the Nogales Tap into the Santa Cruz County service area, additional transmission was not an answer to the peak demand requirements. In order to meet load and not exceed the transmission limit, UNS Electric must run some local generation in Santa Cruz County during peak hours.

Q. Please describe the potential security problems.

A. The system is susceptible to security problems due to the radial nature of the 115kV transmission system. This means that should the 115kV line be severed at any point, all downstream load is interrupted – there is no parallel path to maintain continuity of service. Thus, there are certain outages along the 115kV line which could result in some load not being served, this concern remains even if the existing 115kV line were rebuilt using double circuit construction is used to increase transmission capacity.

Q. Historically, what have been common causes for outages on the 115kV line serving Santa Cruz County?

A. The majority of interruptions are due to uncontrollable events such as storms. During a storm, a lightning strike that might hit in the vicinity of the UNS Electric lines can cause circuit breakers to open for any of the line sections. This would then interrupt power flow on the 115kV transmission line and cause an outage for UNS Electric's customers. Also, strong winds can cause damage to lines or structures. On occasion, a motor vehicle or animal may cause an outage.

Q. Generally, how does UNS Electric respond when one of these outages occurs on its system?

A. Any disruption in the transmission system from Red Rock to Nogales can cause an electrical outage and loss of power to customers located "downstream" from the point of outage.

If the transmission system relays cause the breakers on the line to open and the system operators identify a problem on the transmission system, the generators located in Nogales are started and provide electricity. It can take from twelve to fifteen minutes for the generators to supply electricity in these circumstances. When the cause of the outage has been corrected and/or isolated, the transmission line can be restored to service after synchronizing with the WAPA transmission system. Once the transmission line is back in service, the generators are shut down. These generators are a relatively expensive means of supplying power.

During peak periods, the electric load in Santa Cruz County may be greater than the output of the generators. When an outage occurs under these circumstances, an emergency UNS Electric 46 kV line that ties into TEP's system can provide approximately 10 MW of electricity to northern Santa Cruz County. As discussed in more detail, UNS Electric constructed this 46kV line in 2004.

I should point out, however, that depending upon the location of an outage and the system demand at the time, the combination of the four generators in Nogales and the 46kV line tie may not be sufficient to restore the customers' entire load.

The table provided below indicates the percentage of hours – by year from 2006 through 2012 – that load will likely be above what could be served using the existing 115kV transmission line alone (no local generation on-line).

Year	Percent Annual Hours Load exceeds 65MW
2006	1.7%
2007	2.2%
2008	2.9%
2009	3.4%
2010	4.1%
2011	5.5%
2012	6.3%

Q. How many outages related to the 115kV line have there been in Santa Cruz County in the last 10 years?

A. Over the last 10 years, the outages on the 115kV line have been as follows:

Year	Number of Interruptions (115kV)
1996	6
1997	1
1998	5
1999	6
2000	4
2001	4
2002	0
2003	1
2004	0
2005	5

C. New Facilities to Improve Reliability.

Q. Do you have any concerns regarding reliability of service for Santa Cruz County in the future?

A. Yes, I do. First, current forecasts in Santa Cruz County anticipate the load continuing to exceed 65 MW into the future. This is significant because the transmission wheeling contract with WAPA is only for 65.8 MW in 2006 and beyond. WAPA does not have additional firm transmission capacity available. In order to serve all of the electric loads in Nogales with the forecast peaks, absent contingencies, more transmission capacity is needed or generators must be run to make up the shortfall during peak load hours. The load forecasts show that Santa Cruz County has a very short duration peak. The current Santa Cruz County peak load forecast is listed in Exhibit EAB-3.

The amount of local generation that we expect to be required for the next five years to supplement transmission capability is shown in the table below:

Year	Additional Generation required to meet load not served by 115kV transmission (MW)
2006	4.7
2007	7.0
2008	9.5
2009	12.1
2010	14.7
2011	17.3
2012	19.9

Q. What did UNS Electric believe to be the best immediate solution for Santa Cruz County reliability concerns?

A. UNS Electric determined that the best near term solution to the WAPA transmission limitation was to install a 20 MW combustion turbine at the Valencia substation site in Nogales, particularly because the new generation provides UNS Electric with both (i) immediate needed reliability benefits and (ii) the capability to upgrade the existing 115kV line and pursue a second transmission line. The 20 MW turbine will provide backup during extended transmission outages and provides continuity of service to customers by picking up the load in excess of transmission capacity more efficiently than the older turbines. The generator will limit customer outages to the time it takes for switching and unit startups. This generator provides benefits that the other smaller generators cannot because of start up time, and efficiency.

As noted above, the 20 MW turbine was completed in the Spring of 2006 and was on-line and available for operation for the summer of 2006. The turbine will provide the added capacity to meet reliability requirements of the Nogales demand for another 10 years – and at the lowest cost to the ratepayers.

Finally, the new 20 MW turbine, because of better efficiency, will offer an opportunity for dispatch to the market to offset capital costs, when not needed to serve the Nogales load once UNS Electric is no longer under the full requirements PWCC PSA.

In sum, the new 20 MW turbine is critical to resolving reliability concerns, particularly in the near term and it is a used and useful asset for UNS Electric.

Q. Did UNS Electric consider generation alternatives to the 20MW Turbine?

A. UNS Electric determined that space was available at the Valencia Substation in Nogales for the installation of another generator as large as a Frame 7EA. This type of generator could produce up to 70MW of power. Instead of such a large generator, two smaller generators could be constructed.

The Valencia Substation is a desirable site because it is already developed with gas, water, transmission, and other infrastructure suitable for generation. Generator additions enable restoration of service during transmission outages. Also, when transmission capacity is insufficient to meet load, the generator provides continuity of service to customers by picking up the load in excess of transmission capacity.

The cost of the generation solution depended upon the size of the generator. Budget estimates were $13 Million for a new LM2500 (about 20 MW at Nogales elevation) and approximately $23 Million for an LM6000 (about 40 MW).

Q. What concerns needed to be addressed in deciding what new generation to add at the Valencia site?

A. In assessing generation alternatives, availability of fuel is a critical concern. The current gas supply to the Valencia substation is not sufficient to provide fuel to the three existing combustion turbines and a new generating unit. A new generator, due to its higher efficiency and lower operating costs, would be dispatched first and would be able to run on the available gas. This would require that some of the existing generation be run on oil when needed. About 5,000 gallons of oil is required for each hour of full output from all three existing units. Currently, there are 100,000 gallons of oil storage on site.

Moreover, the existing gas line only supplies about 475 psig of gas pressure and about 600 psig is required for a LM6000 Unit (~40 MW). A smaller LM2500 (~20 MW) or a larger Frame 7EA (~70 MW), were capable of operation at the current gas pressures. The reason for the low existing gas pressures is that the Valencia substation is at the far end of the El Paso Natural Gas ("EPNG") line. Upstream customers, such as Green Valley, Tubac, Continental, Sahuarita and the mines, pull down the gas pressure before it gets to UNS Electric. This upstream impact will only increase with gas use resulting from population growth in the communities north of Nogales. That limitation effectively ruled out the 40MW unit.

Q. Is additional infrastructure needed for additional generation and the three existing turbines to use natural gas?

A. The long term solution to the gas problem is the construction of a second natural gas line to Nogales. EPNG estimates that it would cost about $12 Million to design, build, and construct a suitably sized gas line from their existing system. Another option is to wait for completion of the Sonoran gas line project announced in September 2004. This proposed line would distribute gas from a liquefied natural gas port on the Baja coast to other parts of northern Mexico including an interconnection through Nogales to EPNG. Recent inquiries to EPNG indicate that this project is not yet in the design phase and could take many more years to complete. The phasing of the project is also uncertain.

All of the fuel-related factors resulted in the conclusion that a 20MW unit was the optimal and prudent solution to the impending reliability concerns.

Q. Has UNS Electric constructed any other significant facilities to improve reliability in Santa Cruz County?

A. Yes. UNS Electric and TEP developed a 46kV emergency tie between the UNS Electric system and TEP's system at the Kantor substation. This tie was constructed by UNS Electric in 2004 at a cost of approximately $2.5 million and allows UNS Electric and TEP to shorten restoration time for some outages and supplements the turbines located at Valencia. Connecting those systems directly to UNS Electric, would cause power to flow outside of TEP's two county area and violate two county financing restrictions. This effectively restricts the 46 kV tie between UNS Electric and TEP to being used only when UNS Electric has an emergency that requires the tie to restore service to its customers. If the tie is used during an UNS Electric emergency, it must be reopened immediately after the emergency is over

D. <u>Other Steps to Improve Reliability</u>

Q. Is UNS Electric also planning to take other steps besides installing the 20 MW combustion turbine?

A. As previously noted, the installation of the 20MW generator is considered a near-term interim solution to improve reliability of service while UNS Electric plans and implements the upgrade and conversion of the existing 115kV line serving Nogales to 138kV and pursues a second transmission line to Nogales. These two steps are important to achieve a long term solution for reliable electric service to Santa Cruz County. The upgrade is currently planned to be implemented in four phases with the final phase completed in 2013. The upgrade will provide additional line capacity over the existing wire in the air. In addition, as part of the upgrade, the connection to the regional grid (that is, the interconnection with WAPA's 115kV system) will be relocated from the Nogales Tap to TEP's Vail substation, which is an interconnection with TEP's EHV transmission system. This will relieve a current constraint that UNS Electric faces on the WAPA system. This constraint is contractual in nature because, as previously noted, WAPA only has 65.8 MW of firm capacity under point-to-point service available to commit to UNS Electric.

III. RELIABILITY IN MOHAVE COUNTY.

Q. Mr. Beck, when did UNS Electric begin to provide electric service to Mohave County?

A. UNS Electric began to serve Mohave County in August 2003 upon acquisition of Citizen's Arizona electric systems.

Q. Please describe how UNS Electric presently provides electric power to Mohave County.

A. UNS Electric also obtains electric power for Mohave County under the PWCC PSA. In general terms, PWCC provides full requirements energy and capacity for Mohave County to UNS Electric at Pinnacle Peak and Saguaro Substations. UNS Electric is responsible for delivery of the power from the PWCC delivery points. To do this, UNS Electric has three contracts in place with WAPA for transmission. The reason that UNS Electric has three contracts with WAPA is due to the makeup of WAPA's system. WAPA built and allocates costs for various portions of its system under a project paradigm. Under this concept certain lines and substations that are part of a specific project are taken as one system. WAPA has the Parker Davis Project, the Pacific Intertie Project and the Central Arizona Project for which UNS Electric contracts for transmission service (the Colorado River Storage Project is another project of WAPA's that UNS Electric does not use). See exhibit EAB-4 for a simplified representation of these Project systems.

The WAPA transmission contracts have service limits that have recently been lower than the total load in the UNS Electric territories. As a result UNS Electric has purchased some transmission at peak hours from the California Independent System Operator to supplement the WAPA contracts. Recent UNS Electric discussions with WAPA have identified an ability to convert from contracted point to point service to network service on some of Western's paths, thereby eliminating the contractual limits that have become problematic.

Q. Is the current arrangement for providing electric power to UNS Electric's customers in Mohave County susceptible to reliability problems?

A. According to studies conducted by WAPA, their system presently meets all reliability criteria without violations. As long as the contractual limits can be overcome, there are no immediate reliability issues in serving the Mohave County.

Q. Please describe what must be done to maintain and ultimately improve reliability of electric service in Mohave County.

A. The Mohave County area is also contractually constrained for transmission but WAPA has performed studies and offered network transmission service in the Mohave area that should allow UNS Electric to meet all of its delivery requirements for at least nine years. In addition, UNS Electric is constructing a portion of a 230kV line from North Havasu Substation to Griffith Substation in 2007. Although UNS Electric has requested an extension to its CEC for this line, it intends to complete the project in time to provide additional necessary transmission into the service area and improve reliability.

Additionally, as discussed in detail in the Direct Testimony of Michael J. DeConcini, UNS Electric intends to acquire the BMGS in Mohave County to help to meet some of its load serving needs in Mohave County service area upon the expiration of the PWCC PSA. It is important to note that developing generation such as BMGS within the load area certainly improves reliability of service in the load area. These reliability benefits are in addition to the power supply and operational benefits that Mr. DeConcini has identified and the financial benefits that Kevin P. Larson has identified in his Direct Testimony. Generation located within a service area, when operating, reduces the need for importing energy over the transmission system, helps support voltages within the area and aids in prompt restoration of service.

IV. <u>CONCLUSION</u>.

Q. Do you have any concluding testimony?

A. Yes, I do. UNS Electric has spent extensive time and effort in looking at the UNS Electric system to determine efficient improvements to the system that can improve the ability to provide as much continuity of service and expeditious restoration of service to Santa Cruz County. UNS Electric is committed to providing safe, economical and reliable electricity in Arizona and carefully reviewed various options available for providing such service. The installation of the 20MW generator at Valencia was identified as providing the optimal and most cost-effective solution for ensuring reliable service to Santa Cruz County in the near term, while providing sufficient capacity to allow a reasoned upgrade of the existing 115kV line and a pursuit of a second transmission line to Nogales.

Although reliability is an immediate concern in Mohave County, UNS Electric continues to monitor reliability of service in Mohave County and make improvements when appropriate. The BMGS will improve reliability of service in the Mohave County service area.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT

EAB-1

EXHIBIT EAB-1

Mr. Beck received a Bachelor of Science degree in Civil Engineering and a Masters Degree in Business Administration from the University of Arizona. He is a Registered Professional Engineer in the State of Arizona and a member of the American Society of Civil Engineers.

Mr. Beck has worked in the electric utility industry for over 27 years. Currently he is TEP's representative on the WestConnect regional process, the Arizona Independent System Administrator (including being a member of the AISA's board), Vice-Chair of wesTTrans (the regional open access information system for the region), and Chair of the Market Interface Committee of the WECC.

Prior to assuming his present position, he was project engineer and project manager for various transmission line and substation design projects, Contract Negotiator in contracts and wholesale marketing, Contract Negotiator in system operations for the implementation of the Federal Energy Regulatory Commission's ("FERC") OASIS requirements, and Supervisor of Resource planning. In connection with these assignments, Mr. Beck has designed and managed the construction of 138 kV, 345 kV and 500 kV transmission projects.

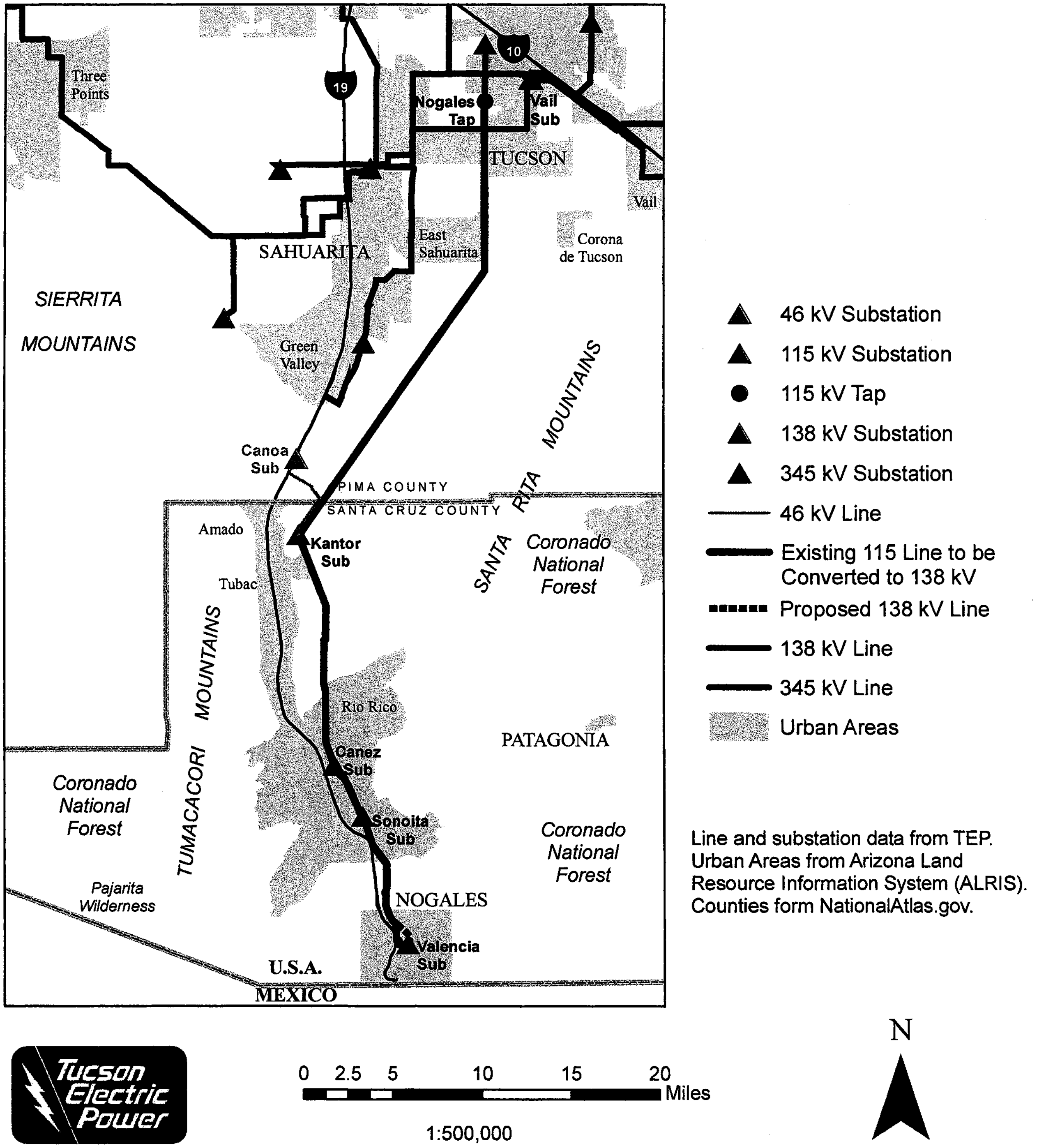
Mr. Beck has also negotiated agreements related to transmission in the region, including development of TEP's Open Access Transmission Tariff, and TEP's FERC rates. He was TEP's lead negotiator in the creation of the Southwest Reserve Sharing Group. He was lead TEP negotiator in a turnkey proposal for peaking resources and ultimately in contract development for a TEP peaking resource project. He was also TEP's primary negotiator for the Project Development Agreement between TEP and Citizens Communications Company ("Citizens") and has been intimately involved in the analysis and review of options to serve load in Santa Cruz County while attempting to obtain approval for a transmission line to the Nogales area.

Mr. Beck testified in FERC proceedings regarding TEP's Open Access Transmission Tariff and Rates, and in Arizona Corporation Commission ("Commission") proceedings regarding TEP transmission issues. He also has testified in an arbitration case involving the TEP transmission system, he has represented the AISA in front of the FERC staff regarding filing issues, and has testified in Congressional hearings related to the need for change in the National Environmental Protection Act directly related to the Nogales transmission project..

EXHIBIT

EAB-2

115 kV Transmission Line Upgrade to 138 kV



Line and substation data from TEP.
Urban Areas from Arizona Land Resource Information System (ALRIS).
Counties form NationalAtlas.gov.

Tucson Electric Power
A UniSource Energy Company

November 28, 2006

G:\OH2\Land Management\Environmental Planning\Projects\gis\ACC\SC_alt_ACC.mxd

EXHIBIT

EAB-3

EXHIBIT EAB-3

Annual Peak Load Forecast for Santa Cruz

Year	Load (MW)
2005	69.6
2006	71.7
2007	74.0
2008	76.5
2009	79.1
2010	81.7
2011	84.3
2012	86.9

EXHIBIT

EAB-4

WAPA

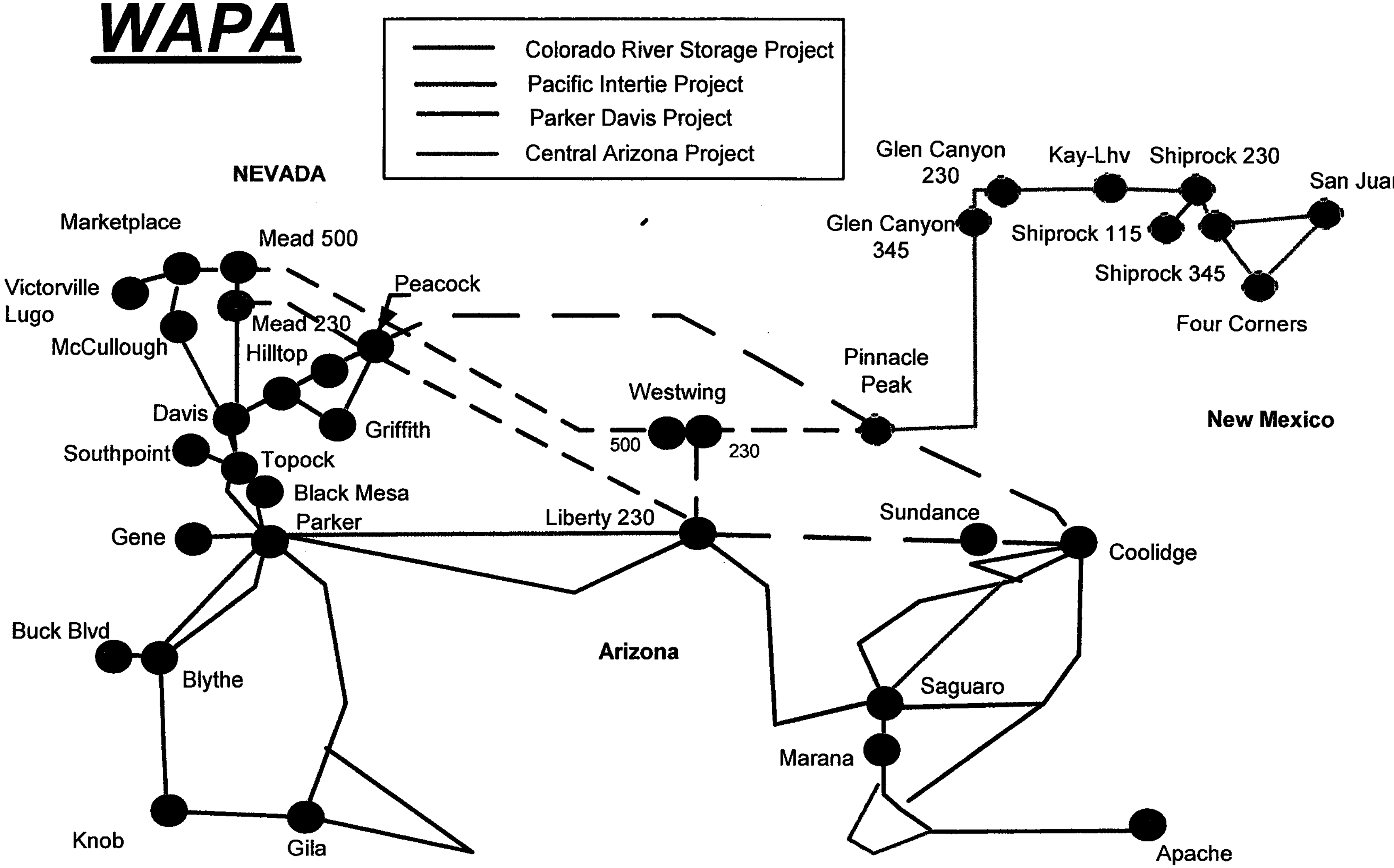


Exhibit EAB-4

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-783

Rebuttal Testimony of

Edmond A. Beck

on Behalf of

UNS Electric, Inc.

August 14, 2007

EXHIBIT
UNSE 31
Admitted

Q. Please state your name and address.

A. My name is Edmond A. Beck. My business address is Tucson Electric Power Company ("TEP"), P.O. Box 711, Tucson, Arizona 85702.

Q. Are you the same Edmond A. Beck that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed Marshall Magruder's Direct Testimony in this case?

A. Yes I have.

Q. Can you please give your overall impression of Mr. Magruder's Direct Testimony?

A. Mr. Magruder discusses at length issues related to reliability. The specific issues he raises are addressed in other dockets at the Commission. In fact, there has been extensive testimony and hearings on many of the issues he tries to – again – raise here. We do not believe that it is appropriate to try and re-litigate those issues in this rate case.

Q. Even so, are there any items within his reliability testimony you feel should be addressed in this case?

A. Yes, there are several items where Mr. Magruder's Direct Testimony is inaccurate. First, Mr. Magruder seems to indicate that UNS Electric rate base should not take into consideration expenses that were incurred by Citizens prior to UNS Electric taking control. This is incorrect. If infrastructure was installed to serve customers, whether by Citizens or by UNS Electric, the costs incurred should be considered as part of the rate base. Second, Mr. Magruder equates electrical load growth to population growth. His "equation" is inaccurate. While there is a correlation between the two – UNS Electric has experienced a larger increase in load than population growth. This is a common phenomenon that most electric utilities experience. The use per customer ("UPC") has been growing in the recent past.

Third, Mr. Magruder may have experience with military use of turbines in the U.S. navy but this does not equate to electric utility operation of turbines. Electric utilities operate the equipment in a more controlled manner to reduce maintenance and extend service life. Also generation capabilities are based on various ratings. Nameplate ratings are the output at the terminals of a generator at a given elevation. There is an adjustment to output based on variations in elevation. Also, when a unit is installed in a plant auxiliary load should be subtracted from the adjusted nameplate rating to get a "nominal" capability. Auxiliary load includes the equipment required to operate the turbine such as pumps and fans. In a Navy installation aboard a ship a turbine is not exposed to the impacts of interconnection across a transmission grid that plays on role in the use of the turbines.

So, while Mr. Magruder may have experience with the general concepts regarding turbine operations, it is a far cry to then proclaim to have extensive expertise in how generation works within a transmission grid. It takes substantial time, training and actual experience working in the utility industry for someone to reach the point where he or she can "plan" transmission. None of Mr. Magruder's experience involves ensuring that utility customers receive reliable energy and planning generation, transmission and distribution that affects an interstate and regional grid.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. G-04204A-06-____

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Gas, Inc.

December 15, 2006

EXHIBIT
UNSE.32
Admitted

Table of Contents

BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. RONALD E. WHITE
IN DOCKET NO. E-___

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am an Executive Vice President and Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the

Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty states, including Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Exhibit REW–1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by UNS Electric, Inc. (UNS Electric), an operating subsidiary of UniSource Energy Services, to conduct a 2006 depreciation rate review for electric utility plant owned and operated by UNS Electric. The purpose of my testimony is to sponsor and describe the review conducted by Foster Associates. Depreciation rates currently used by UNS Electric were approved by the Arizona Corporation Commission (ACC) in Docket No. E–1032–92–073 (Decision No. 58360, dated July 23, 1993).

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WOULD YOU PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors which should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the sum of all reserve is the most important measure of the status of the company's depreciation practices and procedures. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

IV. 2006 Depreciation Rate Review

Q. DID UNS ELECTRIC PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2006 DEPRECIATION REVIEW?

A. Yes, they did. The database used in conducting the 2006 review was assembled by Foster Associates from two sources. The first source was electronic files obtained from Citizens Communications Company (the prior owner of assets acquired by UNS Electric in 2003) containing: a) aged transfers and retirements over the period 1999–August 2003; and b) age distributions of surviving plant at December 31, 2002. The second data source was electronic files obtained from UNS Electric containing plant and reserve activity over the period September 2003–December 2005 and age distributions of surviving plant at December 31, 2005.

Reserve transactions recorded in 2005 were obtained from UNS Electric and used in the 2006 review to distinguish between average and future net salvage rates. Reserve transactions were not available from Citizens.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR UNS ELECTRIC PLANT AND EQUIPMENT?

A. Yes, we did. As discussed in Exhibit REW–2, all plant accounts were analyzed using a technique in which first, second and third degree orthogonal polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

As noted earlier, the database for UNS Electric contains plant accounting transactions for activity years 1999–2005. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[1] A similar limitation applies to the database of UNS Electric which contains only seven (7) activity years. Retirements must be sufficiently distributed across vintages within these seven years to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each plant account for which retirements were recorded over the period 1999–2005. Without exception, the life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Limitations in conducting a life analysis were also exacerbated by the transfer of plant accounting records to UNS Electric from Citizens. Plant activity over the period September 2003–December 31, 2004 was processed by UNS Electric in 2005. This unavoidable delay produced a discontinuity in the available plant history, further reducing the likelihood of deriving meaningful statistical indications.

[1] Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

Pending the availability of sufficient retirement activity to conduct a comprehensive depreciation study, it is the opinion of Foster Associates that currently approved parameters provide the best available estimate of service life statistics and future net salvage rates for the current depreciation review. With the exception of transportation equipment and proposed amortizable categories, projection lives and projection curves recommended in this review were derived from the parameters estimated by Citizens in a 1991 study. Parameters for transportation equipment (not included in the Citizens study) were adopted from a UNS Gas study conducted by Foster Associates in 2006. Projection lives approved for Citizens were adopted as amortization periods for the proposed amortization categories.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR UNS ELECTRIC PLANT AND EQUIPMENT?

A. No, we did not. As noted earlier, historical net salvage data were not available from Citizens for conducting a net salvage analysis. The distinction between average and future net salvage rates was recognized, however, using direct dollar–weighting of 2005 retirements with the 2005 net salvage rates, and future retirements (*i.e.*, surviving plant) with net salvage rates estimated in the 1991 study.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes, we did. Statement C of Exhibit REW–2 provides a comparison of the computed, recorded and redistributed reserves at December 31, 2005. The recorded reserve was $151,589,220 or 43.6 percent of the depreciable plant investment. The corresponding computed reserve is $154,486,143 or 44.4 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $2,896,924 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in the review.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES FOR UNS ELECTRIC?

A. Yes, we are. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of reserves is also needed to eliminate reserve imbalances derived from an initialization of amortization accounting proposed for several intangible and general support asset accounts. Amortization periods proposed for these accounts were used to derive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of both embedded plant and future additions. Plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account by the ratio of the total recorded reserves (net of amortizable accounts) to the calculated total net reserve. The sum of the redistributed reserves is, therefore, equal to the total recorded depreciation reserve before the redistribution.

Q. WOULD YOU PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR UNS ELECTRIC?

A. Current depreciation rates were developed for each primary account in a 1991 study using a depreciation system composed of the straight–line method, broad group procedure, remaining–life technique. The formulation of an account accrual rate using the currently approved depreciation system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR UNS ELECTRIC?

A. No, we are not. While it remains the opinion of Foster Associates that goals and objectives of depreciation accounting can be more nearly achieved using a vintage group procedure, depreciation rates proposed in this review were developed using the currently approved system. A vintage group procedure should be considered when sufficient data become available to conduct a comprehensive depreciation study.

Q. WOULD YOU PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES IS RECOMMENDING FOR UNS ELECTRIC IN THE 2006 REVIEW?

A. Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the study.

	Accrual Rate			2006 Annualized Accrual		
Function	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	3.79%	3.09%	-0.70%	$402,542	$327,637	($74,905)
Other Production	2.00%	2.46%	0.46%	288,814	354,818	66,004
Transmission	3.68%	3.41%	-0.27%	1,561,426	1,448,677	(112,749)
Distribution	4.50%	4.16%	-0.34%	11,708,287	10,816,605	(891,682)
General Plant	8.97%	7.88%	-1.09%	1,800,162	1,581,551	(218,611)
Total	4.53%	4.18%	-0.35%	$15,761,231	$14,529,288	($1,231,943)

Table 2. Depreciation Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 4.18 percent. Depreciation expense is presently accrued at a composite rate of 4.53 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.35 percentage points.

A continued application of rates currently approved would provide annualized depreciation expense of $15,761,231 compared with an annualized expense of $14,529,288 using the rates developed in the review. The resulting 2006 expense decrease is $1,231,943. The computed change in the annualized accrual includes an amortization of $239,117 associated with the measured reserve shortfall. The remaining portion is largely attributable to a change in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Of the 44 primary accounts included in the 2006 review, Foster Associates is recommending rate reductions for 21 plant accounts and rate increases for 23 accounts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT

REW-1

Foster Associates Inc.
17595 S. Tamiami Trail
Suite 212
Fort Myers, FL 33908

Phone (239) 267-1600
Fax (239) 267-5030
E-mail r.white@fosterfm.com

Ronald E. White, Ph.D.

Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

1996 - Present Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State

University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public

Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc., testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company, testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company, testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest, testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas), testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc., rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc., testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U13899, Michigan Consolidated Gas Company, testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P, testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS, testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS, testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation, testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association

Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

December 2006

EXHIBIT

REW-2

Exhibit REW–2

2006 Depreciation Rate Review

UNS Electric, Inc.

Prepared by
Foster Associates, Inc.

FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

17595 S. Tamiami Trail, Suite 212
Fort Myers, Florida 33908
(239) 267-1600 • FAX (239) 267-5030

Ronald E. White, Ph.D.
Executive Vice President

November 24, 2006

Mr. Carl W. Dabelstein
General Manager – Plant Accounting and Tax Services
TUCSON ELECTRIC POWER COMPANY
4350 East Irvington Road
Mail Stop OH121, P.O. Box 771
Tucson, AZ 85702

RE: 2006 Depreciation Rate Review

Dear Mr. Dabelstein:

Foster Associates is pleased to submit our report of a 2006 Depreciation Rate Review for UNS Electric, Inc. This report presents the results of our review leading to a recommendation that UNS Electric seek regulatory authorization to adopt straight–line, broad–group, remaining–life rates and record depreciation expense using primary account accrual rates that composite to 4.18 percent.

The following table provides a comparison of present and proposed depreciation rates and accruals for calendar year 2006, based upon plant investments and deprecation reserves at December 31, 2005.

	Accrual Rate			2006 Annualized Accrual		
Function	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	3.79%	3.09%	-0.70%	$402,542	$327,637	($74,905)
Other Production	2.00%	2.46%	0.46%	288,814	354,818	66,004
Transmission	3.68%	3.41%	-0.27%	1,561,426	1,448,677	(112,749)
Distribution	4.50%	4.16%	-0.34%	11,708,287	10,816,605	(891,682)
General Plant	8.97%	7.88%	-1.09%	1,800,162	1,581,551	(218,611)
Total	4.53%	4.18%	-0.35%	$15,761,231	$14,529,288	($1,231,943)

A continued application of currently approved rates would provide annual depreciation expense of $15,761,231 compared with an annual expense of $14,529,288 using the rates recommended in the study. The resulting change in depreciation rates produces an annualized 2006 expense reduction of $1,231,943.

The scope of our investigation included:

- Collection of plant and net salvage data;
- Reconciliation of an assembled database to Company records;

- Discussions with UNS Electric plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Estimation of average and future net salvage rates;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

The results of our investigation are presented in the attached report in five sections. The Executive Summary provides an overview of the review and a discussion of the principal findings. The Company Profile provides background information about UNS Electric that is foundational to the review. The Study Procedure section describes the steps involved in conducting a comprehensive depreciation study and the specific procedures used in this engagement. The Statements provide a comparative summary of present and proposed depreciation parameters, rates and accruals. The report concludes with the Analysis section containing an example of supporting schedules prepared for each plant account.

We wish to express our appreciation for this opportunity to be of service to UNS Electric and for the assistance provided to us. We would be pleased to discuss our review with you or others at your convenience.

Respectively submitted,
FOSTER ASSOCIATES, INC.
by

Ronald E. White, Ph.D.
Executive Vice President

REW:ml

CONTENTS

DISTRIBUTION

364.00 – POLES, TOWERS AND FIXTURES

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for electric utility plant owned and operated by UNS Electric, Inc. (UNS Electric), an operating subsidiary of UniSource Energy Services, Inc. Work on this review, conducted by Foster Associates, Inc. (Foster Associates), commenced in July 2006 and progressed through mid–November 2006, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by our Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by UNS Electric were developed from parameters *(i.e.*, projection lives, projection curves and net salvage rates) developed in a 1991 study conducted by Citizens Utilities Company (Citizens), the prior owner of assets acquired by UNS Electric in 2003. Rates developed in the 1991 study were approved by the Arizona Corporation Commission (ACC) in Docket No. E–1032–92–073 (Decision No. 58360, dated July 23, 1993).[1] UNS Electric adopted the depreciation rates approved for Citizens. Foster Associates was advised that no parameters have been adjusted subsequent to the 1991 study.

The principal findings and recommendations of the 2006 UNS Electric Depreciation Rate Review are summarized in the Statements section of this report. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of recorded and computed depreciation reserves for each rate category. Statement D provides a summary of the components used to obtain a weighted–average

[1] Depreciation rates were not discussed in Docket No. E–1039–95–433 (Decision No. 59951, dated January 3, 1997) or in Docket Nos. E–01032C–00–0751 consolidated with Docket Nos. Docket No. G–01032A–02–0598, E–01933A–02–0914, E–01032C–02–0914 and G–01032A–02–0914 (Order 66028 dated July 3, 2003).

net salvage rate for each plant account. Statement E provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF REVIEW

The principal activities undertaken in the 2006 review included:

- Collection of plant and reserve data;
- Reconciliation of an assembled database to Company records;
- Discussions with UNS Electric plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Estimation of average and future net salvage rates;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping dictates the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

UNS Electric is currently using a depreciation system composed of the straight–line method, broad group procedure, remaining–life technique for all plant categories. The present system was approved by the ACC in Docket No. E–1032–92–073 without comment as to the appropriateness of the system or a consideration of alternative systems. Pending the availability of sufficient data to conduct a comprehensive depreciation study, the currently approved system was retained in this review.

In addition to adjustments to depreciation rates, Foster Associates is recommending amortization accounting for selected general support asset categories in which the unit cost of equipment is small in relation to the cost of maintaining detailed accounting records and several intangible accounts associated with contract agreements. Depreciation accounting would be replaced with amortization accounting for the asset categories summarized in Table 1.

Account Number	Description	Amortization Period
A	B	C
Intantible Plant		
302.00	Franchises and Consents	25 yrs.
303.00	Miscellaneous Intangible Plant	15 yrs.
303.WC	Misc. Intangible Plant - WAPA Fiber Optic	23 yrs.
303.PC	Misc. Intangible Plant - PC Software	5 yrs.
General Plant		
391.10	Office Furniture and Equipment	21 yrs.
391.20	Computer Equipment - PCs	5 yrs.
393.00	Stores Equipment	33 yrs.
394.00	Tools, Shop and Garage Equipment	29 yrs.
395.00	Laboratory Equipment	40 yrs.
397.CE	Communication Equipment	23 yrs.
398.00	Miscellaneous Equipment	18 yrs.

Table 1. Proposed Amortization Accounts

Amortization periods recommended by Foster Associates were used to derive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of both embedded plant and future additions. Plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Reserve imbalances created by the amortization periods recommended in this review were eliminated by a systematic redistribution of recorded reserves. Net salvage realized in the future will be netted against then current–year vintage additions.

RECOMMENDED DEPRECIATION RATES

Table 2 provides a summary of the changes in annual rates and accruals resulting from the 2006 review.

Function	Accrual Rate			2006 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	3.79%	3.09%	-0.70%	$402,542	$327,637	($74,905)
Other Production	2.00%	2.46%	0.46%	288,814	354,818	66,004
Transmission	3.68%	3.41%	-0.27%	1,561,426	1,448,677	(112,749)
Distribution	4.50%	4.16%	-0.34%	11,708,287	10,816,605	(891,682)
General Plant	8.97%	7.88%	-1.09%	1,800,162	1,581,551	(218,611)
Total Utility	4.53%	4.18%	-0.35%	$15,761,231	$14,529,288	($1,231,943)

Table 2. Present and Proposed Rates and Accruals

The composite accrual rate recommended for UNS Electric is 4.18 percent. The current equivalent rate is 4.53 percent. The recommended change in the composite rate is a decrease of 0.35 percentage points.

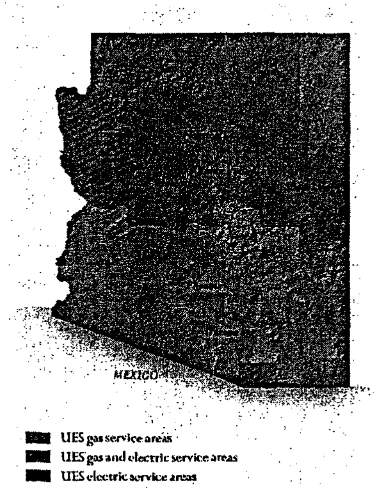
A continued application of current rates would provide annualized depreciation expense of $15,761,231 compared with an annualized expense of $14,529,288 using the proposed rates. The resulting 2006 expense reduction of $1,231,943 is largely attributable to a change in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Of the 44 primary accounts included in the 2006 review, Foster Associates is recommending rate reductions for 21 plant accounts and rate increases for 23 accounts.

COMPANY PROFILE

GENERAL

UNS Electric provides electric utility services to portions of Mohave and Santa Cruz Counties in Arizona. The Company serves approximately 72,200 customers in Mohave County and nearly 20,000 customers in Santa Cruz County. Customer growth has averaged about 6 percent per year for the last 10 years. Approximately 85 percent of customers are residential and 15 percent are commercial and industrial.



Major communities served are Lake Havasu City and Kingman in Mohave County. Lake Havasu City is a premier tourist destination in the southwest. Major industry in Lake Havasu City consists of boat manufacturing and Sterilite Industries, a plastic containers manufacturer. Kingman has a strong manufacturing base, producing products such as electrical wiring, plastic conduit, building insulation, paper products, and finished cabinets.

Nogales is located on the Mexican border and is Arizona's inland port for a billion–dollar produce transportation industry. The Maquiladora, or twin plant industry, is also an important economic engine for the area. These plants provide shipping and supplies for manufacturers located in the sister city of Nogales, Sonora in Mexico.

ELECTRIC UTILITY OPERATIONS

All of the energy required to meet the needs of Mohave County is purchased from Pinnacle West Capital Corporation (PWCC) and is transmitted over high-voltage lines owned and operated by Western Area Power Administration (WAPA). UNS Electric's transmission facilities include 69 kV lines that connect WAPA's bulk power delivery points to distribution substations throughout the service territory. Mohave operations currently do not have any generation facilities. System peaks occur during the summer months. Lake Havasu City's peak in 2006 was approximately 200 MW while Kingman's peak was about 160 MW.

Santa Cruz energy needs are mostly provided by PWCC as well. The Company owns and operates about 70 MW of gas/diesel fueled generation in Nogales. These units are primarily used as back–up for a 50 mile, 115 kV transmission line which is connected to the WAPA system near Tucson, Arizona.

UNS Electric employs 175 personnel in operations, engineering, customer service, billing services and administration.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by UNS Electric. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting the 2006 depreciation review can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2006 review for UNS Electric included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of a study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in a life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distribution of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a data file. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to the Company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by UNS Electric provides aged transactions for all plant accounts.

The database used in conducting the 2006 review was assembled by Foster Associates from two sources. The first source was electronic files obtained from Citizens Communications Company containing: a) aged transfer and retirements over the period 1999–August 2003; and b) age distributions of surviving plant at December 31, 2002. The second data source was electronic files obtained from UNS Electric containing plant and reserve activity over the period September 2003–December 2005 and age distributions of surviving plant at December 31, 2005.

Reserve transactions recorded in 2005 were obtained from UNS Electric and used in the 2006 review to distinguish between average and future net salvage rates. Reserve transactions were not available from Citizens.

Age distributions of surviving plant at December 31, 2005 and activity year transactions over the period 1999–2005 were coded by Foster Associates and used to derive plant additions and opening age distributions at January 1, 1999. The transfer of assets to UNS Electric from Citizens prevented Foster Associates from reconciling the assembled database to any public reports of Citizens. The integrity of the database, however, was verified for activity years 2004 and 2005 for data provided by UNS Electric.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of service life known as the *projection life* of an account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of the life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2006 UNS Electric depreciation review.

An actuarial life analysis program designed and developed by Foster Associates was used in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this review. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this review are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed in terms of a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and average service life.

Options available in the Foster Associates actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

As noted earlier, the database for UNS Electric contains plant accounting transactions for activity years 1999–2005. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[2] A similar limitation applies to the database of UNS Electric which contains only seven (7) activity years. Retirements must be sufficiently distributed across vintages within these seven years to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each plant account for which retirements were recorded over the period 1999–2005. Without exception, the life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of

[2] Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

activity years.

Limitations in conducting a life analysis were also exacerbated by the transfer of plant accounting records to UNS Electric from Citizens. Plant activity over the period September 2003–December 31, 2004 was processed by UNS Electric in 2005. This unavoidable delay produced a discontinuity in the available plant history, further reducing the likelihood of deriving meaningful statistical indications.

Pending the availability of sufficient retirement activity to conduct a comprehensive depreciation study, it is the opinion of Foster Associates that currently approved parameters provide the best available estimate of service life statistics and future net salvage rates for the current depreciation review. With the exception of transportation equipment and proposed amortizable categories, projection lives and projection curves recommended in this review were derived from the parameters estimated by Citizens in the 1991 study. Parameters for transportation equipment (not included in the Citizens study) were adopted from a UNS Gas study conducted by Foster Associates in 2006. Projection lives approved for Citizens were adopted as amortization periods for the proposed amortization categories.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides an appropriate basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

As noted earlier, historical net salvage data were not available from Citizens for conducting a net salvage analysis. The distinction between average and future net salvage rates was recognized, however, using direct dollar–weighting of 2005 retirements with the 2005 net salvage rates, and future retirements (*i.e.*, surviving plant) with net salvage rates estimated in the 1991 study. The computation of the estimated average net salvage rate for each rate category is shown in Statement D.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of a recorded reserve with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for UNS Electric at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current review should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of reserve is also needed to eliminate reserve imbalances created by the initialization of amortization accounting proposed for the accounts summarized in Table 1. Amortization periods proposed for these accounts were used to derive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of both embedded plant and future additions. Plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Depreciation reserves for amortizable categories were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account by the ratio of the total recorded reserves (net of amortizable accounts) to the calculated total net reserve. The sum of the redistributed reserves is, therefore, equal to the total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of the computed, recorded and redistributed reserves at December 31, 2005. The recorded reserve was $151,589,220 or 43.6 percent of the depreciable plant investment. The corresponding computed reserve is $154,486,143 or 44.4 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $2,896,924 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash in-flows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not alter the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. The whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates currently used by UNS Electric were developed using a system composed of the straight–line method, broad group procedure, remaining–life technique.[3] While it remains the opinion of Foster Associates that goals and objectives of depreciation accounting can be more nearly achieved using a vintage group procedure, depreciation rates proposed in this review were developed using the currently approved system. A vintage group procedure should be considered when sufficient data become available to conduct a comprehensive depreciation study.

It is also the opinion of Foster Associates that adoption of amortization accounting as proposed in this review is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Adoption of amortization accounting will relieve UNS Electric of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the asset.

[3] The present system was approved by the ACC in Docket No. E–1032–92–073 without comment as to the appropriateness of the system or a consideration of alternative systems.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life statistics recommended for UNS Electric. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates using the broad group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized 2006 depreciation accruals based upon the depreciation rates developed in Statement A.
- Statement C provides a comparison of recorded and computed reserves at December 31, 2005 and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each rate category.
- Statement E provides a comparative summary of present and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains present and proposed statistics including average service life, average remaining life and average net salvage rates.

Present depreciation accruals shown on Statement B are the product of the plant investment (Column B) and present depreciation rates (Column D) shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2005. Similarly, proposed depreciation accruals shown on Statement B are the product of the plant investment and the proposed depreciation rates (Column H) shown on Statement A. The proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}$$

This formulation of the accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

UNS ELECTRIC, INC.

Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	38.00		2.92%	30.16		5.64%	3.13%
Total Depreciable			2.92%	30.16		5.64%	3.13%
Amortizable							
302.00 Franchises and Consents	38.00			← 25 Year Amortization →			
303.00 Miscellaneous Intangible Plant	38.20			← 15 Year Amortization →			
303.WC Misc. Intangible - WAPA Fiber Optic	38.20		4.13%	← 23 Year Amortization →			
303.PC Misc.Intangible Plant - PC Software	31.00		20.00%	← 5 Year Amortization →			
Total Amortizable			4.23%	7.21		61.05%	3.06%
Total Intangible Plant			3.79%	10.88		42.48%	3.09%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	38.00		1.38%	29.50		39.01%	2.07%
342.00 Fuel Holders, Producers and Accessories	38.20		2.42%	32.63		18.06%	2.51%
343.00 Prime Movers	37.00		2.34%	26.17		33.89%	2.53%
344.00 Generators	22.60		0.67%	36.15		15.62%	2.33%
345.00 Accessory Electric Equipment	39.50		2.20%	29.39		31.02%	2.35%
346.00 Miscellaneous Power Plant Equipment	31.00		1.87%	33.34		12.02%	2.64%
Total Other Production Plant			2.00%	28.73		29.41%	2.46%
TRANSMISSION PLANT							
350.RW Rights of Way				31.35		36.56%	2.02%
352.00 Structures and Improvements	19.70		3.77%	12.75		60.15%	3.13%
353.00 Station Equipment	23.00		2.92%	21.72		31.49%	3.15%
354.00 Towers and Fixtures	12.40		4.08%	15.92		20.00%	5.03%
355.00 Poles and Fixtures	15.90	-10.0%	5.77%	12.68	-10.0%	53.19%	4.48%
356.00 Overhead Conductors and Devices	30.10		2.71%	23.85		36.50%	2.66%
359.00 Roads and Trails	44.90		2.01%	35.18		29.05%	2.02%
Total Transmission Plant			3.68%	18.90	-2.9%	39.12%	3.41%
DISTRIBUTION PLANT							
360.RW Rights of Way				27.71		43.70%	2.03%
361.00 Structures and Improvements	23.60		3.20%	25.54		24.39%	2.96%
362.00 Station Equipment	15.30		4.82%	11.54		52.77%	4.09%
364.00 Poles, Towers and Fixtures	18.90	-10.0%	4.23%	14.83	-10.0%	48.65%	4.14%
365.00 Overhead Conductors and Devices	18.40	-10.0%	4.36%	15.16	-10.0%	47.39%	4.13%
366.00 Underground Conduit	21.50		4.28%	18.66	-5.0%	34.33%	3.79%
367.00 Underground Conductors and Devices	14.30		5.36%	14.20		37.50%	4.40%
368.00 Line Transformers	14.20	-5.0%	4.93%	13.46	-5.0%	42.69%	4.63%
369.OH Services - Overhead	18.30		4.23%	14.43		45.63%	3.77%
369.UG Services - Underground	18.30		4.23%	16.26		38.99%	3.75%
370.00 Meters	26.20	-5.0%	3.25%	24.14	-5.0%	29.99%	3.11%
373.00 Street Lighting and Signal Systems	17.40		4.55%	16.64		32.78%	4.04%
Total Distribution Plant			4.50%	14.75	-6.0%	44.74%	4.16%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	27.80		2.89%	29.03		23.14%	2.65%
392.C1 Transportation Equipment - Class 1			25.00%	4.00		49.01%	12.75%
392.C2 Transportation Equipment - Class 2			25.00%	3.02		48.68%	16.99%
392.C3 Transportation Equipment - Class 3			25.00%	3.28		33.72%	20.21%
392.C4 Transportation Equipment - Class 4			12.50%	1.63		78.05%	13.47%
392.C5 Transportation Equipment - Class 5			12.50%	6.58		17.40%	12.55%
396.00 Power Operated Equipment	6.80		3.33%	5.16		64.30%	6.92%
Total Depreciable			12.12%	4.13		54.16%	11.33%

UNS ELECTRIC, INC. Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
Amortizable							
391.10 Office Furniture and Equipment	17.60		3.72%	← 21 Year Amortization →			
391.20 Computer Equipment - PCs			20.00%	← 5 Year Amortization →			
393.00 Stores Equipment	28.10		2.62%	← 33 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	23.80		3.02%	← 29 Year Amortization →			
395.00 Laboratory Equipment	33.30		2.41%	← 40 Year Amortization →			
397.CE Communication Equipment	17.60		4.13%	← 23 Year Amortization →			
398.00 Miscellaneous Equipment	11.60		5.45%	← 18 Year Amortization →			
Total Amortizable			5.10%	11.20		41.95%	3.65%
Total General Plant			8.97%	6.21	-4.9%	48.69%	7.88%
TOTAL UTILITY			4.53%	14.29	-4.9%	43.58%	4.18%

UNS ELECTRIC, INC. Statement B

Comparison of Present and Proposed Accruals .
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	2006 Annualized Accrual Proposed	2006 Annualized Accrual Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
Depreciable				
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$103,906	$111,378	$7,472
Total Depreciable	$3,558,415	$103,906	$111,378	$7,472
Amortizable				
302.00 Franchises and Consents	$11,908		$54	$54
303.00 Miscellaneous Intangible Plant	4,219,098		141,762	141,762
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	69,591	73,298	3,707
303.PC Misc.Intangible Plant - PC Software	1,145,223	229,045	1,145	(227,900)
Total Amortizable	$7,061,229	$298,636	$216,259	($82,377)
Total Intangible Plant	$10,619,644	$402,542	$327,637	($74,905)
OTHER PRODUCTION PLANT				
341.00 Structures and Improvements	$619,244	$8,546	$12,818	$4,272
342.00 Fuel Holders, Producers and Accessories	631,364	15,279	15,847	568
343.00 Prime Movers	8,684,079	203,207	219,707	16,500
344.00 Generators	2,309,132	15,471	53,803	38,332
345.00 Accessory Electric Equipment	1,685,197	37,074	39,602	2,528
346.00 Miscellaneous Power Plant Equipment	493,979	9,237	13,041	3,804
Total Other Production Plant	$14,422,995	$288,814	$354,818	$66,004
TRANSMISSION PLANT				
350.RW Rights of Way	$346,016		$6,990	$6,990
352.00 Structures and Improvements	191,668	7,226	5,999	(1,227)
353.00 Station Equipment	17,657,646	515,603	556,216	40,613
354.00 Towers and Fixtures	521,825	21,290	26,248	4,958
355.00 Poles and Fixtures	12,285,169	708,854	550,376	(158,478)
356.00 Overhead Conductors and Devices	11,245,657	304,757	299,134	(5,623)
359.00 Roads and Trails	183,860	3,696	3,714	18
Total Transmission Plant	$42,431,841	$1,561,426	$1,448,677	($112,749)
DISTRIBUTION PLANT				
360.RW Rights of Way	$86,619		$1,758	$1,758
361.00 Structures and Improvements	3,398,247	108,744	100,588	(8,156)
362.00 Station Equipment	28,402,465	1,368,999	1,161,661	(207,338)
364.00 Poles, Towers and Fixtures	75,596,882	3,197,748	3,129,711	(68,037)
365.00 Overhead Conductors and Devices	48,310,770	2,106,350	1,995,235	(111,115)
366.00 Underground Conduit	12,126,868	519,030	459,608	(59,422)
367.00 Underground Conductors and Devices	22,976,392	1,231,535	1,010,961	(220,574)
368.00 Line Transformers	45,658,424	2,250,960	2,113,985	(136,975)
369.OH Services - Overhead	7,297,945	308,703	275,133	(33,570)
369.UG Services - Underground	3,315,090	140,228	124,316	(15,912)
370.00 Meters	9,368,222	304,467	291,352	(13,115)
373.00 Street Lighting and Signal Systems	3,769,729	171,523	152,297	(19,226)
Total Distribution Plant	$260,307,653	$11,708,287	$10,816,605	($891,682)

UNS ELECTRIC, INC. Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	2006 Annualized Accrual Proposed	Difference
A	B	C	D	E=D-C
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$2,445,738	$70,682	$64,812	($5,870)
392.C1 Transportation Equipment - Class 1	366,331	91,583	46,707	(44,876)
392.C2 Transportation Equipment - Class 2	882,290	220,573	149,901	(70,672)
392.C3 Transportation Equipment - Class 3	1,007,316	251,829	203,579	(48,250)
392.C4 Transportation Equipment - Class 4	4,808,218	601,027	647,667	46,640
392.C5 Transportation Equipment - Class 5	584,467	73,058	73,351	293
396.00 Power Operated Equipment	968,258	32,243	67,003	34,760
Total Depreciable	$11,062,618	$1,340,995	$1,253,020	($87,975)
Amortizable				
391.10 Office Furniture and Equipment	$2,297,349	$85,461	$103,610	$18,149
391.20 Computer Equipment - PCs	868,777	173,755	15,030	(158,725)
393.00 Stores Equipment	122,871	3,219	3,698	479
394.00 Tools, Shop and Garage Equipment	2,391,755	72,231	79,406	7,175
395.00 Laboratory Equipment	808,108	19,475	20,203	728
397.CE Communication Equipment	2,391,716	98,778	100,691	1,913
398.00 Miscellaneous Equipment	114,643	6,248	5,893	(355)
Total Amortizable	$8,995,219	$459,167	$328,531	($130,636)
Total General Plant	$20,057,837	$1,800,162	$1,581,551	($218,611)
TOTAL UTILITY	$347,839,970	$15,761,231	$14,529,288	($1,231,943)

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$238,117	6.69%	$204,609	5.75%	$200,560	5.64%
Total Depreciable	$3,558,415	$238,117	6.69%	$204,609	5.75%	$200,560	5.64%
Amortizable							
302.00 Franchises and Consents	$11,908	$0		$11,775	98.88%	$11,775	98.88%
303.00 Miscellaneous Intangible Plant	4,219,098	267,350	6.34%	2,971,824	70.44%	2,971,824	70.44%
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	159,478	9.46%	183,152	10.87%	183,152	10.87%
303.PC Misc.Intangible Plant - PC Software	1,145,223	1,178,678	102.92%	1,144,041	99.90%	1,144,041	99.90%
Total Amortizable	$7,061,229	$1,605,507	22.74%	$4,310,792	61.05%	$4,310,792	61.05%
Total Intangible Plant	$10,619,644	$1,843,624	17.36%	$4,515,401	42.52%	$4,511,352	42.48%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	$619,244	$367,625	59.37%	$246,434	39.80%	$241,558	39.01%
342.00 Fuel Holders, Producers and Accessories	631,364	121,053	19.17%	116,329	18.43%	114,027	18.06%
343.00 Prime Movers	8,684,079	2,637,958	30.38%	3,002,520	34.58%	2,943,108	33.89%
344.00 Generators	2,309,132	254,855	11.04%	367,850	15.93%	360,571	15.62%
345.00 Accessory Electric Equipment	1,685,197	450,671	26.74%	533,384	31.65%	522,830	31.02%
346.00 Miscellaneous Power Plant Equipment	493,979	71,873	14.55%	60,577	12.26%	59,379	12.02%
Total Other Production Plant	$14,422,995	$3,904,034	27.07%	$4,327,095	30.00%	$4,241,473	29.41%
TRANSMISSION PLANT							
350.RW Rights of Way	$346,016	$1		$129,064	37.30%	$126,510	36.56%
352.00 Structures and Improvements	191,668	147,919	77.17%	117,614	61.36%	115,287	60.15%
353.00 Station Equipment	17,657,646	6,525,850	36.96%	5,672,519	32.13%	5,560,274	31.49%
354.00 Towers and Fixtures	521,825	144,146	27.62%	106,452	20.40%	104,346	20.00%
355.00 Poles and Fixtures	12,285,169	6,414,872	52.22%	6,665,775	54.26%	6,533,877	53.19%
356.00 Overhead Conductors and Devices	11,245,657	4,276,151	38.02%	4,187,528	37.24%	4,104,667	36.50%
359.00 Roads and Trails	183,860	73,249	39.84%	54,496	29.64%	53,418	29.05%
Total Transmission Plant	$42,431,841	$17,582,187	41.44%	$16,933,449	39.91%	$16,598,378	39.12%
DISTRIBUTION PLANT							
360.RW Rights of Way	$86,619	$0		$38,615	44.58%	$37,851	43.70%
361.00 Structures and Improvements	3,398,247	824,191	24.25%	845,564	24.88%	828,832	24.39%
362.00 Station Equipment	28,402,465	14,346,966	50.51%	15,291,887	53.84%	14,989,299	52.77%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
364.00 Poles, Towers and Fixtures	75,596,882	35,977,383	47.59%	37,523,576	49.64%	36,781,079	48.65%
365.00 Overhead Conductors and Devices	48,310,770	22,914,406	47.43%	23,357,935	48.35%	22,895,740	47.39%
366.00 Underground Conduit	12,126,868	4,060,572	33.48%	4,247,436	35.03%	4,163,389	34.33%
367.00 Underground Conductors and Devices	22,976,392	9,724,089	42.32%	8,790,967	38.26%	8,617,016	37.50%
368.00 Line Transformers	45,658,424	21,572,430	47.25%	19,885,236	43.55%	19,491,757	42.69%
369.OH Services - Overhead	7,297,945	3,359,775	46.04%	3,397,599	46.56%	3,330,369	45.63%
369.UG Services - Underground	3,315,090	1,044,451	31.51%	1,318,669	39.78%	1,292,576	38.99%
370.00 Meters	9,368,222	2,871,949	30.66%	2,865,926	30.59%	2,809,217	29.99%
373.00 Street Lighting and Signal Systems	3,769,729	1,250,480	33.17%	1,260,597	33.44%	1,235,653	32.78%
Total Distribution Plant	$260,307,653	$117,946,692	45.31%	$118,824,008	45.65%	$116,472,780	44.74%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$2,445,738	$800,583	32.73%	$577,323	23.61%	$565,899	23.14%
392.C1 Transportation Equipment - Class 1	366,331	274,470	74.92%	183,166	50.00%	179,541	49.01%
392.C2 Transportation Equipment - Class 2	882,290	615,312	69.74%	438,204	49.67%	429,533	48.68%
392.C3 Transportation Equipment - Class 3	1,007,316	706,361	70.12%	346,517	34.40%	339,660	33.72%
392.C4 Transportation Equipment - Class 4	4,808,218	4,578,490	95.22%	3,828,544	79.63%	3,752,786	78.05%
392.C5 Transportation Equipment - Class 5	584,467	95,384	16.32%	103,743	17.75%	101,690	17.40%
396.00 Power Operated Equipment	968,258	732,737	75.68%	635,177	65.60%	622,609	64.30%
Total Depreciable	$11,062,618	$7,803,339	70.54%	$6,112,673	55.26%	$5,991,718	54.16%
Amortizable							
391.10 Office Furniture and Equipment	$2,297,349	$764,125	33.26%	$912,876	39.74%	$912,876	39.74%
391.20 Computer Equipment - PCs	868,777	62,880	7.24%	851,825	98.05%	851,825	98.05%
393.00 Stores Equipment	122,871	57,010	46.40%	68,689	55.90%	68,689	55.90%
394.00 Tools, Shop and Garage Equipment	2,391,755	950,482	39.74%	1,096,139	45.83%	1,096,139	45.83%
395.00 Laboratory Equipment	808,108	198,068	24.51%	286,621	35.47%	286,621	35.47%
397.CE Communication Equipment	2,391,716	387,217	16.19%	473,306	19.79%	473,306	19.79%
398.00 Miscellaneous Equipment	114,643	89,560	78.12%	84,062	73.33%	84,062	73.33%
Total Amortizable	$8,995,219	$2,509,343	27.90%	$3,773,518	41.95%	$3,773,518	41.95%
Total General Plant	$20,057,837	$10,312,681	51.41%	$9,886,191	49.29%	$9,765,236	48.69%
TOTAL UTILITY	$347,839,970	$151,589,220	43.58%	$154,486,143	44.41%	$151,589,220	43.58%

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
Depreciable									
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415		$3,558,415						
Total Depreciable	$3,558,415		$3,558,415						
Amortizable									
302.00 Franchises and Consents	$11,908		$11,908						
303.00 Miscellaneous Intangible Plant	4,219,099	1	4,219,098						
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC Misc.Intangible Plant - PC Software	1,145,223		1,145,223						
Total Amortizable	$7,061,230	$1	$7,061,229						
Total Intangible Plant	$10,619,645	$1	$10,619,644						
OTHER PRODUCTION PLANT									
341.00 Structures and Improvements	$619,244		$619,244						
342.00 Fuel Holders, Producers and Accessories	631,364		631,364						
343.00 Prime Movers	10,707,541	2,023,462	8,684,079						
344.00 Generators	2,356,732	47,600	2,309,132						
345.00 Accessory Electric Equipment	1,904,534	219,337	1,685,197						
346.00 Miscellaneous Power Plant Equipment	503,598	9,619	493,979						
Total Other Production Plant	$16,723,013	$2,300,018	$14,422,995						
TRANSMISSION PLANT									
350.RW Rights of Way	$346,016		$346,016						
352.00 Structures and Improvements	191,668		191,668						
353.00 Station Equipment	17,697,125	39,479	17,657,646						
354.00 Towers and Fixtures	521,825		521,825						
355.00 Poles and Fixtures	12,393,414	108,245	12,285,169		-10.0%		(1,228,517)	(1,228,517)	-9.9%
356.00 Overhead Conductors and Devices	11,267,316	21,659	11,245,657						
359.00 Roads and Trails	183,860		183,860						
Total Transmission Plant	$42,601,224	$169,383	$42,431,841		-2.9%		($1,228,517)	($1,228,517)	-2.9%
DISTRIBUTION PLANT									
360.RW Rights of Way	$86,619		$86,619						
361.00 Structures and Improvements	3,409,388	11,141	3,398,247						
362.00 Station Equipment	28,425,896	23,431	28,402,465						
364.00 Poles, Towers and Fixtures	76,698,662	1,101,780	75,596,882	-0.8%	-10.0%	(8,814)	(7,559,688)	(7,568,502)	-9.9%
365.00 Overhead Conductors and Devices	49,287,987	977,217	48,310,770	-1.8%	-10.0%	(17,590)	(4,831,077)	(4,848,667)	-9.8%
366.00 Underground Conduit	12,235,191	108,323	12,126,868	0.1%	-5.0%	108	(606,343)	(606,235)	-5.0%
367.00 Underground Conductors and Devices	23,284,235	307,843	22,976,392	-0.8%		(2,463)		(2,463)	
368.00 Line Transformers	47,077,581	1,419,157	45,658,424	-5.9%	-5.0%	(83,730)	(2,282,921)	(2,366,651)	-5.0%
369.OH Services - Overhead	7,297,945		7,297,945						
369.UG Services - Underground	3,315,090		3,315,090						
370.00 Meters	9,760,332	392,110	9,368,222		-5.0%		(468,411)	(468,411)	-4.8%
373.00 Street Lighting and Signal Systems	3,840,377	70,648	3,769,729						
Total Distribution Plant	$264,719,303	$4,411,650	$260,307,653	-2.5%	-6.0%	($112,489)	($15,748,441)	($15,860,930)	-6.0%

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$2,445,743	$5	$2,445,738						
392.C1 Transportation Equipment - Class 1	456,297	89,966	366,331						
392.C2 Transportation Equipment - Class 2	1,183,990	301,700	882,290						
392.C3 Transportation Equipment - Class 3	1,802,214	794,898	1,007,316						
392.C4 Transportation Equipment - Class 4	4,853,150	44,932	4,808,218						
392.C5 Transportation Equipment - Class 5	584,467		584,467						
396.00 Power Operated Equipment	968,258		968,258						
Total Depreciable	$12,294,119	$1,231,501	$11,062,618						
Amortizable									
391.10 Office Furniture and Equipment	$5,955,915	$3,658,566	$2,297,349						
391.20 Computer Equipment - PCs	868,777		868,777						
393.00 Stores Equipment	122,871		122,871						
394.00 Tools, Shop and Garage Equipment	2,455,025	63,270	2,391,755						
395.00 Laboratory Equipment	864,222	56,114	808,108						
397.CE Communication Equipment	2,432,124	40,408	2,391,716						
398.00 Miscellaneous Equipment	114,643		114,643						
Total Amortizable	$12,813,577	$3,818,358	$8,995,219						
Total General Plant	$25,107,696	$5,049,859	$20,057,837						
TOTAL UTILITY	$359,770,881	$11,930,911	$347,839,970	-0.9%	-4.9%	($112,489)	($16,976,958)	($17,089,447)	-4.8%

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

	Present Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc. Intangible - WAPA Switchboard	49.00	S6	49.00	38.00			32.00	R1	32.00	30.16		
Total Depreciable									32.00	30.16		
Amortizable												
302.00 Franchises and Consents	49.00	S6	49.00	38.00			25.00	SQ	25.00	2.50		
303.00 Miscellaneous Intangible Plant	40.00	S4	40.00	38.20			15.00	SQ	15.00	8.81		
303.WO Misc. Intangible - WAPA Fiber Optic	40.00	S4	40.00	38.20			23.00	SQ	23.00	20.50		
303.PC Misc.Intangible Plant - PC Software	36.00	R1	36.00	31.00			5.00	SQ	5.00	1.00		
Total Amortizable									12.09	7.21		
Total Intangible Plant									15.27	10.88		
OTHER PRODUCTION PLANT												
341.00 Structures and Improvements	49.00	S6	49.00	38.00			49.00	S6	49.00	29.50		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	38.20			40.00	S4	40.00	32.63		
343.00 Prime Movers	40.00	R3	40.00	37.00			40.00	R3	40.00	26.17		
344.00 Generators	43.00	S0	43.00	22.60			43.00	S0	43.00	36.15		
345.00 Accessory Electric Equipment	43.00	S6	43.00	39.50			43.00	S6	43.00	29.39		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	36.00	31.00			38.00	R1	38.00	33.34		
Total Other Production Plant									41.04	28.73		
TRANSMISSION PLANT												
350.RW Rights of Way							50.00	SQ	50.00	31.35		
352.00 Structures and Improvements	33.00	R3	33.00	19.70			33.00	R3	33.00	12.75		
353.00 Station Equipment	32.00	R1	32.00	23.00			32.00	R1	32.00	21.72		
354.00 Towers and Fixtures	20.00	L0	20.00	12.40			20.00	L0	20.00	15.92		
355.00 Poles and Fixtures	25.00	S5	25.00	15.90	-10.0	-10.0	25.00	S5	25.00	12.68	-9.9	-10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	30.10			38.00	L3	38.00	23.85		
359.00 Roads and Trails	50.00	SQ	50.00	44.90			50.00	SQ	50.00	35.18		
Total Transmission Plant									30.71	18.90	-2.9	-2.9
DISTRIBUTION PLANT												
360.RW Rights of Way							50.00	SQ	50.00	27.71		
361.00 Structures and Improvements	34.00	R4	34.00	23.60			34.00	R4	34.00	25.54		
362.00 Station Equipment	25.00	S4	25.00	15.30			25.00	S4	25.00	11.54		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	18.90	-10.0	-10.0	27.00	S4	27.00	14.83	-9.9	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	18.40	-10.0	-10.0	27.00	S3	27.00	15.16	-9.8	-10.0

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Account Description	Present Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
366.00 Underground Conduit	28.00	S2	26.00	21.50			28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.30			23.00	S3	23.00	14.20		
368.00 Line Transformers	23.00	S4	23.00	14.20	-5.0	-5.0	23.00	S4	23.00	13.46	-5.0	-5.0
369.OH Services - Overhead	27.00	R5	27.00	18.30			27.00	R5	27.00	14.43		
369.UG Services - Underground	27.00	R5	27.00	18.30			27.00	R5	27.00	16.26		
370.00 Meters	34.00	R3	34.00	26.20	-5.0	-5.0	34.00	R3	34.00	24.14	-4.8	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	17.40			25.00	S4	25.00	16.64		
Total Distribution Plant									25.87	14.75	-6.0	-6.0
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	36.00	27.80			38.00	R2	38.00	29.03		
392.C1 Transportation Equipment - Class 1							8.00	L1.5	8.00	4.00		
392.C2 Transportation Equipment - Class 2							6.00	L2	6.00	3.02		
392.C3 Transportation Equipment - Class 3							5.00	S5	5.00	3.28		
392.C4 Transportation Equipment - Class 4							8.00	S4	8.00	1.63		
392.C5 Transportation Equipment - Class 5							8.00	S4	8.00	6.58		
396.00 Power Operated Equipment	15.00	S5	15.00	6.80			15.00	S5	15.00	5.16		
Total Depreciable									9.24	4.13		
Amortizable												
391.10 Office Furniture and Equipment	21.00	R2	21.00	17.60			21.00	SQ	21.00	13.37		
391.20 Computer Equipment - PCs	5.00		5.00				5.00	SQ	5.00	1.13		
393.00 Stores Equipment	33.00	S6	33.00	28.10			33.00	SQ	33.00	14.67		
394.00 Tools, Shop and Garage Equipment	29.00	S-.5	29.00	23.80			29.00	SQ	29.00	16.32		
395.00 Laboratory Equipment	40.00	R4	40.00	33.30			40.00	SQ	40.00	25.85		
397.CE Communication Equipment	23.00	R1.5	23.00	17.60			23.00	SQ	23.00	19.07		
398.00 Miscellaneous Equipment	18.00	R4	18.00	11.60			18.00	SQ	18.00	5.19		
Total Amortizable									17.99	11.20		
Total General Plant									11.82	6.21	-4.8	-4.9
TOTAL UTILITY									24.51	14.29	-4.8	-4.9

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the UNS Electric depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 364.00 – Poles, Towers and Fixtures. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the UNS Electric review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

Schedule E – Graphics Analysis

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived projection life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

Schedule F – Historical Net Salvage Analysis

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

UNS Electric, Inc.

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 27 - S4
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	December 31, 2005 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2005	0.5	2,486,752	27.00	26.50	0.9815	1.0000	2,440,701	92,102
2004	1.5	3,106,087	27.00	25.50	0.9444	1.0000	2,933,527	115,040
2003	2.5	1,216,447	27.00	24.50	0.9074	1.0000	1,103,813	45,054
2002	3.5	2,515,741	27.00	23.50	0.8704	1.0000	2,189,635	93,176
2001	4.5	3,113,175	27.00	22.50	0.8333	1.0000	2,594,323	115,303
2000	5.5	211,055	27.00	21.50	0.7963	1.0000	168,062	7,817
1999	6.5	11,336,691	27.00	20.50	0.7593	1.0000	8,607,476	419,877
1998	7.5	2,237,387	26.97	19.50	0.7229	1.0000	1,617,456	82,946
1997	8.5	689,519	26.95	18.50	0.6865	1.0000	473,338	25,586
1996	9.5	7,029,321	27.00	17.50	0.6481	1.0000	4,556,043	260,343
1995	10.5	2,582,221	27.00	16.50	0.6111	1.0000	1,577,982	95,631
1994	11.5	745,981	27.00	15.50	0.5743	1.0000	428,384	27,634
1993	12.5	3,382,758	27.00	14.51	0.5373	1.0000	1,817,434	125,285
1992	13.5	3,230,092	27.01	13.52	0.5004	1.0000	1,616,205	119,577
1991	14.5	4,956,608	26.99	12.54	0.4644	1.0000	2,302,022	183,636
1990	15.5	2,732,296	27.01	11.57	0.4285	1.0000	1,170,787	101,174
1989	16.5	2,964,367	27.01	10.63	0.3936	1.0000	1,166,711	109,731
1988	17.5	3,419,793	27.03	9.73	0.3598	1.0000	1,230,585	126,516
1987	18.5	894,285	26.98	8.86	0.3285	1.0000	293,789	33,146
1986	19.5	442,547	27.11	8.05	0.2970	1.0000	131,427	16,326
1985	20.5	1,673,418	27.17	7.29	0.2684	1.0000	449,196	61,592
1984	21.5	726,503	27.24	6.60	0.2422	1.0000	175,945	26,672
1983	22.5	827,762	27.39	5.96	0.2176	1.0000	180,131	30,221
1982	23.5	1,987,567	27.57	5.38	0.1953	1.0000	388,149	72,096
1981	24.5	542,227	27.58	4.87	0.1764	1.0000	95,651	19,661
1980	25.5	946,685	27.96	4.40	0.1574	1.0000	148,963	33,861
1979	26.5	2,396,702	28.44	3.98	0.1400	1.0000	335,611	84,284
1978	27.5	3,211,813	29.02	3.61	0.1243	1.0000	399,362	110,673
1977	28.5	209,987	27.62	3.27	0.1185	1.0000	24,893	7,603
1976	29.5	543,934	29.48	2.97	0.1009	1.0000	54,865	18,449
1975	30.5	218,295	29.06	2.70	0.0931	1.0000	20,316	7,511
1974	31.5	173,625	30.20	2.46	0.0815	1.0000	14,148	5,749
1973	32.5	133,218	32.70	2.24	0.0685	1.0000	9,129	4,074
1972	33.5	459,179	33.42	2.04	0.0611	1.0000	28,057	13,738
1971	34.5	189,012	34.24	1.86	0.0543	1.0000	10,265	5,520
1970	35.5	173,623	35.31	1.69	0.0479	1.0000	8,321	4,917
1969	36.5	131,330	36.53	1.54	0.0422	1.0000	5,539	3,595

UNS Electric, Inc.

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 27 - S4
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	December 31, 2005 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1968	37.5	144,122	37.48	1.40	0.0374	1.0000	5,390	3,846
1967	38.5	64,338	38.27	1.27	0.0332	1.0000	2,134	1,681
1966	39.5	72,955	39.19	1.15	0.0293	1.0000	2,139	1,862
1965	40.5	120,287	40.50	1.04	0.0257	1.0000	3,096	2,970
1964	41.5	53,632	39.72	0.93	0.0235	1.0000	1,259	1,350
1963	42.5	48,662	42.42	0.82	0.0194	1.0000	942	1,147
1962	43.5	50,113	43.50	0.68	0.0156	1.0000	779	1,152
1961	44.5	66,723	44.36	0.29	0.0066	1.0000	444	1,504
1960	45.5	46,842	45.50			1.0000		
1959	46.5	89,630	46.50			1.0000		
1958	47.5	9,994	47.50			1.0000		
1957	48.5	7,013	48.13			1.0000		
1956	49.5	13,751	49.39			1.0000		
1955	50.5	452,076	50.49			1.0000		
1954	51.5	6,889	51.50			1.0000		
1953	52.5	188,937	52.49			1.0000		
1952	53.5	133,495	53.03			1.0000		
1951	54.5	53,618	54.50			1.0000		
1950	55.5	26,870	55.50			1.0000		
1949	56.5	7,178	54.28			1.0000		
1948	57.5	7,197	56.02			1.0000		
1947	58.5	2,637	58.50			1.0000		
1946	59.5	2,155	59.50			1.0000		
1945	60.5	2,564	60.50			1.0000		
1944	61.5	87,220	61.50			1.0000		
1943	62.5	(15)	62.50			1.0000		
1942	63.5	299	63.50			1.0000		
1941	64.5	1,314	64.50			1.0000		
1939	66.5	696	60.42			1.0000		
1938	67.5	(2,316)	67.50			1.0000		
Total	13.6	$75,596,882	27.78	14.99	0.5395	1.0000	$40,784,426	$2,721,627

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Age Distribution

				Experience to 12/31/2005		
Vintage	Age as of 12/31/2005	Derived Additions	1999 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2005	0.5	2,486,752		2,486,752	1.0000	0.5000
2004	1.5	3,106,087		3,106,087	1.0000	1.5000
2003	2.5	1,216,447		1,216,447	1.0000	2.5000
2002	3.5	2,516,303		2,515,741	0.9998	3.4999
2001	4.5	3,113,837		3,113,175	0.9998	4.4999
2000	5.5	211,055		211,055	1.0000	5.5000
1999	6.5	11,336,617		11,336,691	1.0000	6.5000
1998	7.5		2,239,204	2,237,387	0.9992	7.4739
1997	8.5		703,513	689,519	0.9801	8.4492
1996	9.5		7,029,125	7,029,321	1.0000	9.5003
1995	10.5		2,581,380	2,582,221	1.0003	10.5018
1994	11.5		746,644	745,981	0.9991	11.4951
1993	12.5		3,381,815	3,382,758	1.0003	12.5002
1992	13.5		3,231,251	3,230,092	0.9996	13.5115
1991	14.5		4,968,652	4,956,608	0.9976	14.4885
1990	15.5		2,733,001	2,732,296	0.9997	15.4988
1989	16.5		2,964,608	2,964,367	0.9999	16.4996
1988	17.5		3,420,584	3,419,793	0.9998	17.4995
1987	18.5		905,289	894,285	0.9878	18.4219
1986	19.5		442,973	442,547	0.9990	19.5041
1985	20.5		1,674,543	1,673,418	0.9993	20.4960
1984	21.5		731,675	726,503	0.9929	21.4600
1983	22.5		832,520	827,762	0.9943	22.4636
1982	23.5		2,006,559	1,987,567	0.9905	23.4385
1981	24.5		586,914	542,227	0.9239	24.1819
1980	25.5		1,045,351	946,685	0.9056	25.2211
1979	26.5		2,481,789	2,396,702	0.9657	26.2808
1978	27.5		3,294,378	3,211,813	0.9749	27.3654
1977	28.5		409,749	209,987	0.5125	26.3802
1976	29.5		693,994	543,934	0.7838	28.5857
1975	30.5		390,603	218,295	0.5589	28.4333
1974	31.5		237,022	173,625	0.7325	29.7731
1973	32.5		135,026	133,218	0.9866	32.4187
1972	33.5		476,777	459,179	0.9631	33.2495
1971	34.5		204,030	189,012	0.9264	34.1394
1970	35.5		185,408	173,623	0.9364	35.2522
1969	36.5		131,330	131,330	1.0000	36.5000
1968	37.5		146,821	144,122	0.9816	37.4599

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2005	Derived Additions	1999 Opening Balance	Experience to 12/31/2005 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1967	38.5		67,067	64,338	0.9593	38.2660
1966	39.5		77,631	72,955	0.9398	39.1833
1965	40.5		120,287	120,287	1.0000	40.5000
1964	41.5		80,650	53,632	0.6650	39.7238
1963	42.5		49,234	48,662	0.9884	42.4245
1962	43.5		50,113	50,113	1.0000	43.5000
1961	44.5		68,469	66,723	0.9745	44.3620
1960	45.5		46,842	46,842	1.0000	45.5000
1959	46.5		89,630	89,630	1.0000	46.5000
1958	47.5		9,994	9,994	1.0000	47.5000
1957	48.5		7,637	7,013	0.9183	48.1323
1956	49.5		14,178	13,751	0.9699	49.3946
1955	50.5		463,742	452,076	0.9748	50.4874
1954	51.5		6,889	6,889	1.0000	51.5000
1953	52.5		193,905	188,937	0.9744	52.4872
1952	53.5		143,491	133,495	0.9303	53.0292
1951	54.5		53,618	53,618	1.0000	54.5000
1950	55.5		26,947	26,870	0.9972	55.4986
1949	56.5		11,477	7,178	0.6254	54.2786
1948	57.5		9,316	7,197	0.7725	56.0215
1947	58.5		2,637	2,637	1.0000	58.5000
1946	59.5		2,155	2,155	1.0000	59.5000
1945	60.5		2,564	2,564	1.0000	60.5000
1944	61.5		87,220	87,220	1.0000	61.5000
1943	62.5		(15)	(15)	1.0000	62.5000
1942	63.5		299	299	1.0000	63.5000
1941	64.5		1,314	1,314	1.0000	64.5000
1940	65.5		(1,019)		0.0000	65.0000
1939	66.5		10,919	696	0.0638	60.4226
1938	67.5		(2,316)	(2,316)	1.0000	67.5000
1937	68.5		4,162		0.0000	62.0000
Total		$23,987,097	$52,711,565	$75,596,882	0.9856	

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	52,580,717	10,854,857	409,237		63,026,336
2000	63,026,336	150,073	75,955	(219,014)	62,881,440
2001	62,881,440	3,113,837	260,141	380,517	66,115,653
2002	66,115,653	2,520,236	235,882	493,240	68,893,247
2003	68,893,247	983,343	45,961	14,732	69,845,361
2004	69,845,361			(69,495)	69,775,866
2005	69,775,866	5,895,620	74,604		75,596,882

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1999	52,580,717	10,854,857	409,237		63,026,336
2000	63,026,336	150,073	75,955	(219,014)	62,881,440
2001	62,881,440	3,113,837	260,141	380,517	66,115,653
2002	66,115,653	2,520,236	235,882	493,240	68,893,247
2003	68,893,247	1,286,124	45,961	14,732	70,148,142
2004	70,148,142	3,106,087		(69,495)	73,184,734
2005	73,184,734	2,486,752	74,604		75,596,882

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1965-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2000	69.2	49.4	L1.5 *	4.41	41.6	S1.5 *	4.20	148.4	SC *	3.58
2000-2001	69.8	55.4	L1.5 *	6.49	43.0	S2 *	5.79	141.6	SC *	5.37
2001-2002	58.5	47.7	L2 *	7.89	39.3	S2 *	6.85	115.4	O3 *	6.21
2002-2003	76.5	62.5	L1.5 *	3.57	47.2	S2 *	2.97	145.8	SC *	2.63
2003-2004	95.7	140.8	R1 *	0.96	87.1	S1.5	0.90	191.6	R5 *	0.78
2004-2005	97.2	128.2	S0 *	1.34	89.5	S1.5 *	1.50	190.3	R5 *	1.42

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1965-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2005	84.9	64.4	L1.5 *	2.75	51.8	S1.5 *	3.73	164.3	R1 *	2.31
2001-2005	87.6	70.7	L1.5 *	2.45	53.8	S2 *	3.34	167.2	R1 *	2.61
2003-2005	96.3	121.4	S0 *	1.24	80.4	S1.5	1.52	188.2	R5 *	1.38
2005-2005	93.0	100.5	L1.5 *	1.57	74.8	S1.5 *	1.80	183.6	R4 *	1.54

UNS Electric, Inc.

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1965-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

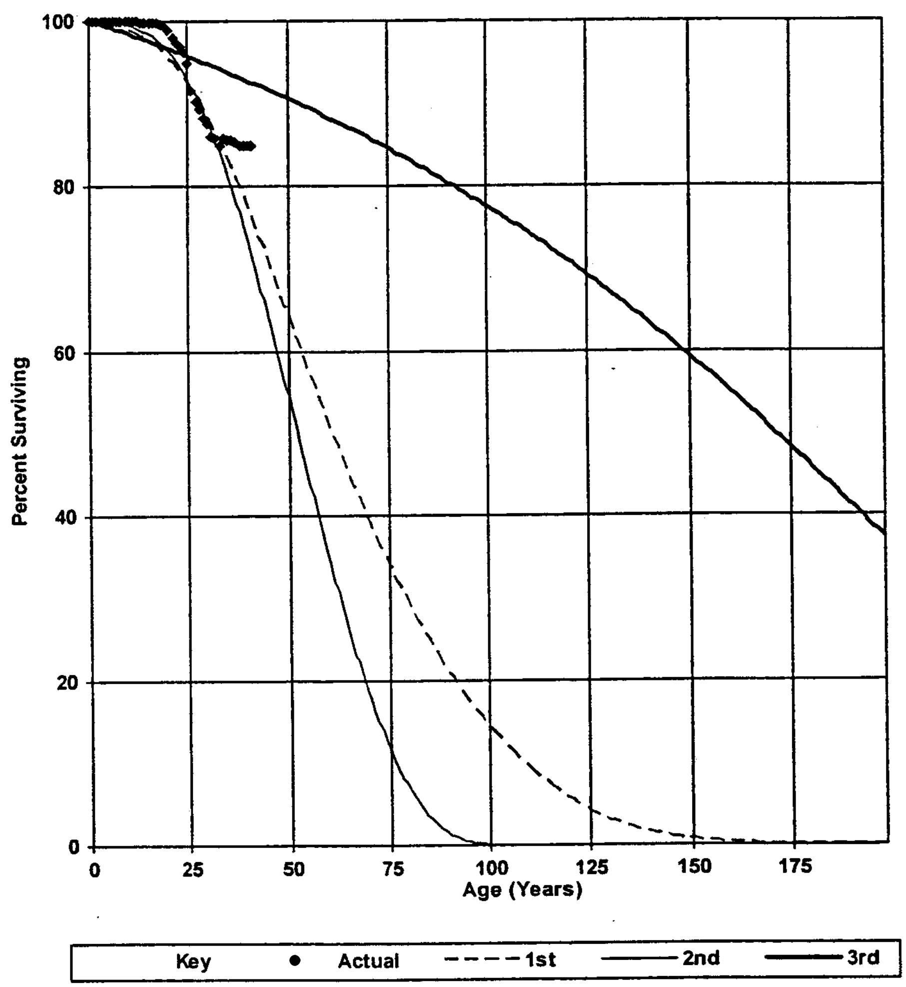
		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1999-2005	84.9	64.4	L1.5*	2.75	51.8	S1.5*	3.73	164.3	R1*	2.31

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1965-2005 Observation Band: 1999-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

1st: 64.4-L1.5 2nd: 51.8-S1.5 3rd: 164.3-R1



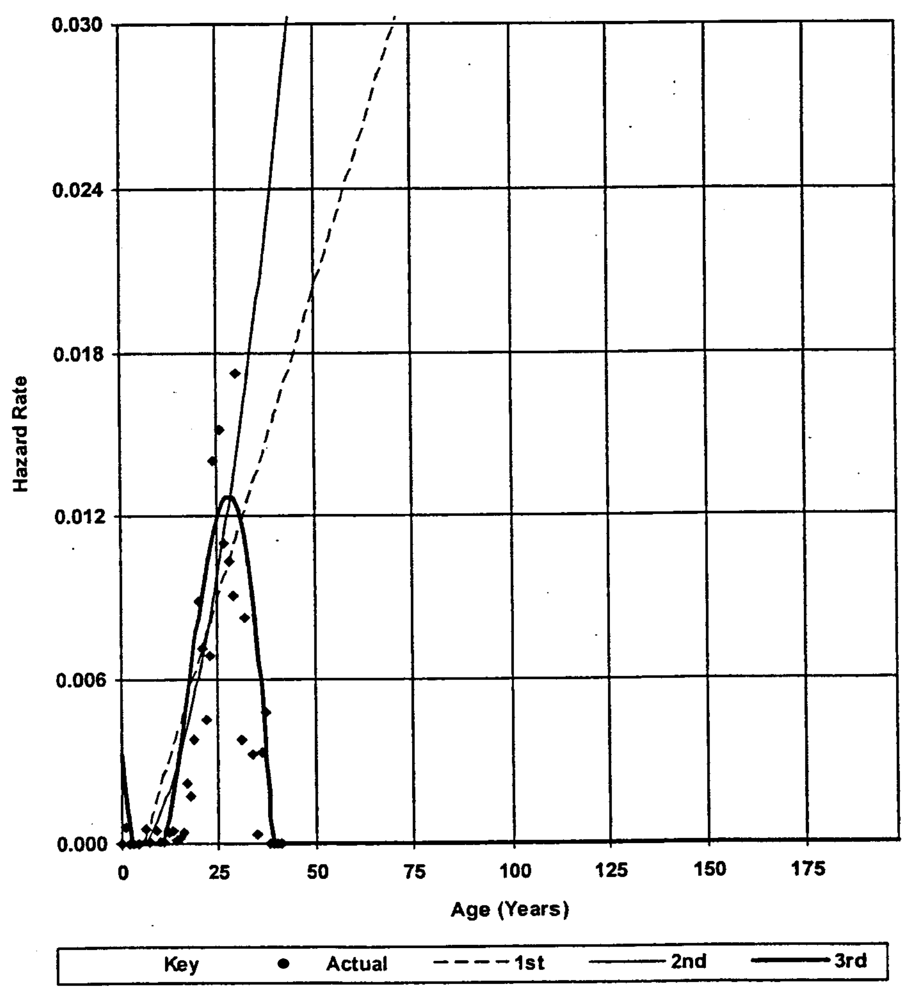
Schedule E

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1965-2005 Observation Band: 1999-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function

1st: 64.4-L1.5 2nd: 51.8-S1.5 3rd: 164.3-R1



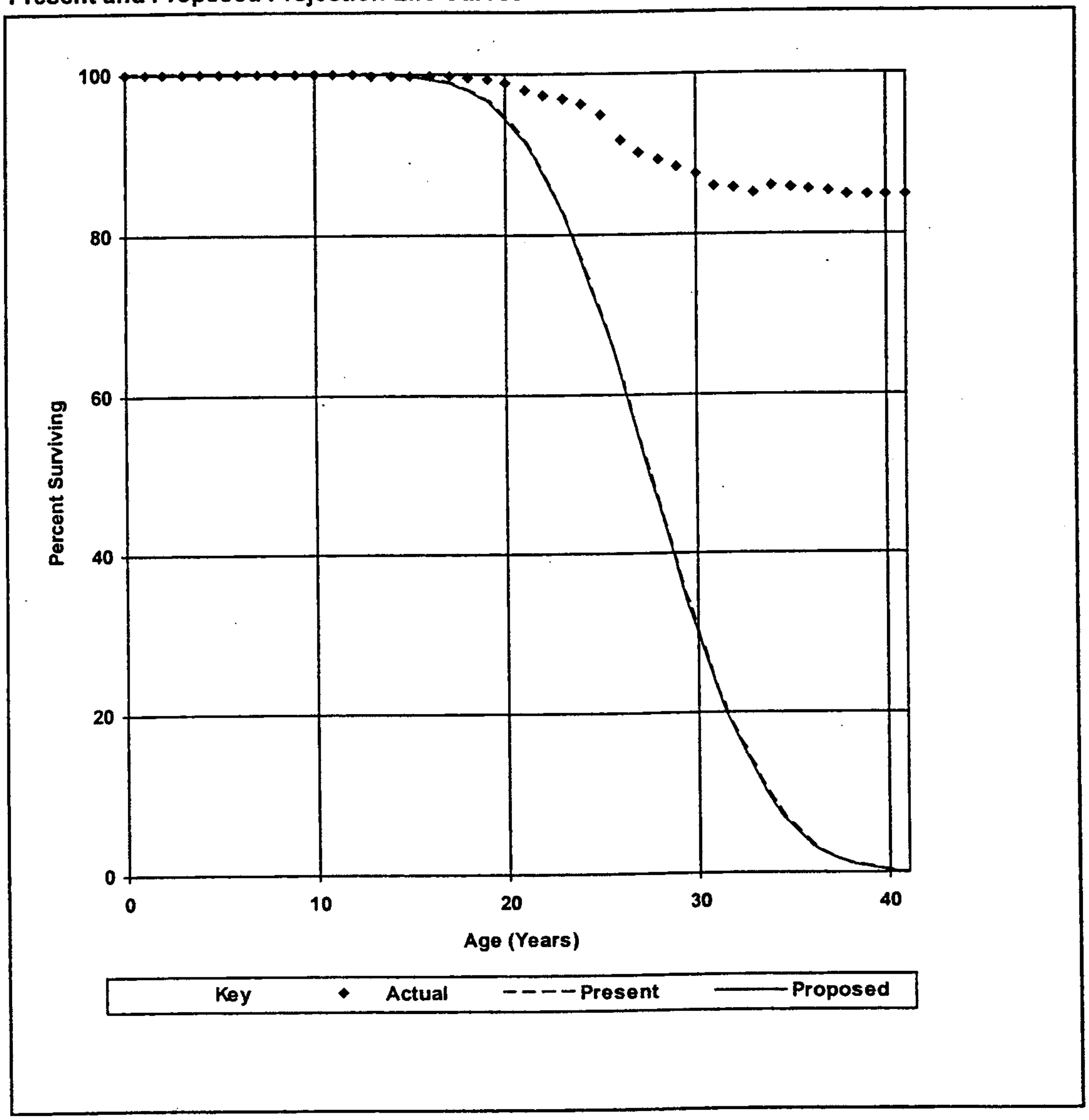
UNS Electric, Inc.

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1965-2005
Observation Band: 1999-2005

Present and Proposed Projection Life Curves Present: 27.0-S4 Proposed: 27.0-S4



UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2005	74,604		0.0		8,976	12.0		(8,976)	-12.0	
Total	74,604		0.0		8,976	12.0		(8,976)	-12.0	

UNS Electric, Inc.
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2005	74,604		0.0		8,976	12.0		(8,976)	-12.0	
Total	74,604		0.0		8,976	12.0		(8,976)	-12.0	

UNS ELECTRIC, INC.'s RESPONSES TO
STAFF'S ELEVENTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 14, 2007

STF 11.8 Refer to the response to STF 3.39.

a. Please provide the detailed recalculation of the corrected depreciation rate for Transportation Equipment.

b. Please provide the detailed calculations and workpapers for the $143,297 reduction to the 2006 annualized accrual to reflect a 10 percent net salvage rate for UNS Electric transportation equipment.

RESPONSE:

a. Please see STF 11.8, Bates Nos. UNSE(0783)08910 to UNSE(0783)08919, on the enclosed CD for the detailed recalculation of the corrected depreciation rate to Transportation Equipment.

b. Please see the calculation for the $143,297 reduction below:

14,385,991 – 14,529,288 = (143,297)

RESPONDENT: Dr. Ronald White

WITNESS: Dr. Ronald White

EXHIBIT
UNSE 33
Admitted

UNS ELECTRIC, INC.
Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Statement A

Account Description	Present Rem. Life	Present Net Salvage	Present Accrual Rate	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	38.00		2.92%	30.16		5.66%	3.13%
Total Depreciable			2.92%	30.16		5.66%	3.13%
Amortizable							
302.00 Franchises and Consents	38.00			← 25 Year Amortization →			
303.00 Miscellaneous Intangible Plant	38.20			← 15 Year Amortization →			
303.WC Misc. Intangible - WAPA Fiber Optic	38.20		4.13%	← 23 Year Amortization →			
303.PC Misc.Intangible Plant - PC Software	31.00		20.00%	← 5 Year Amortization →			
Total Amortizable			4.23%	7.21		61.05%	3.06%
Total Intangible Plant			3.79%	10.88		42.49%	3.09%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	38.00		1.38%	29.50		39.14%	2.06%
342.00 Fuel Holders, Producers and Accessories	38.20		2.42%	32.63		18.12%	2.51%
343.00 Prime Movers	37.00		2.34%	26.17		34.01%	2.52%
344.00 Generators	22.60		0.67%	36.15		15.67%	2.33%
345.00 Accessory Electric Equipment	39.50		2.20%	29.39		31.13%	2.34%
346.00 Miscellaneous Power Plant Equipment	31.00		1.87%	33.34		12.06%	2.64%
Total Other Production Plant			2.00%	28.73		29.51%	2.45%
TRANSMISSION PLANT							
350.RW Rights of Way				31.35		36.69%	2.02%
352.00 Structures and Improvements	19.70		3.77%	12.75		60.36%	3.11%
353.00 Station Equipment	23.00		2.92%	21.72		31.60%	3.15%
354.00 Towers and Fixtures	12.40		4.08%	15.92		20.07%	5.02%
355.00 Poles and Fixtures	15.90	-10.0%	5.77%	12.68	-10.0%	53.37%	4.47%
356.00 Overhead Conductors and Devices	30.10		2.71%	23.85		36.63%	2.66%
359.00 Roads and Trails	44.90		2.01%	35.18		29.16%	2.01%
Total Transmission Plant			3.68%	18.90	-2.9%	39.25%	3.41%
DISTRIBUTION PLANT							
360.RW Rights of Way				27.71		43.85%	2.03%
361.00 Structures and Improvements	23.60		3.20%	25.54		24.48%	2.96%
362.00 Station Equipment	15.30		4.82%	11.54		52.96%	4.08%
364.00 Poles, Towers and Fixtures	18.90	-10.0%	4.23%	14.83	-10.0%	48.82%	4.13%
365.00 Overhead Conductors and Devices	18.40	-10.0%	4.36%	15.16	-10.0%	47.56%	4.12%
366.00 Underground Conduit	21.50		4.28%	18.66	-5.0%	34.45%	3.78%
367.00 Underground Conductors and Devices	14.30		5.36%	14.20		37.63%	4.39%
368.00 Line Transformers	14.20	-5.0%	4.93%	13.46	-5.0%	42.84%	4.62%
369.OH Services - Overhead	18.30		4.23%	14.43		45.79%	3.76%
369.UG Services - Underground	18.30		4.23%	16.26		39.13%	3.74%
370.00 Meters	26.20	-5.0%	3.25%	24.14	-5.0%	30.09%	3.10%
373.00 Street Lighting and Signal Systems	17.40		4.55%	16.64		32.89%	4.03%
Total Distribution Plant			4.50%	14.75	-6.0%	44.90%	4.15%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	27.80		2.89%	29.03		23.22%	2.64%
392.C1 Transportation Equipment - Class 1			25.00%	4.00	10.0%	44.07%	11.48%
392.C2 Transportation Equipment - Class 2			25.00%	3.02	10.0%	43.82%	15.29%
392.C3 Transportation Equipment - Class 3			25.00%	3.28	10.0%	28.71%	18.69%
392.C4 Transportation Equipment - Class 4			12.50%	1.63	10.0%	70.49%	11.97%
392.C5 Transportation Equipment - Class 5			12.50%	6.58	10.0%	15.71%	11.29%
396.00 Power Operated Equipment	8.80		3.33%	5.16		64.53%	6.87%
Total Depreciable			12.12%	4.13	6.9%	49.82%	10.29%

UNS ELECTRIC, INC. **Statement A**

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
Amortizable							
391.10 Office Furniture and Equipment	17.60		3.72%	← 21 Year Amortization →			
391.20 Computer Equipment - PCs			20.00%	← 5 Year Amortization →			
393.00 Stores Equipment	28.10		2.62%	← 33 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	23.80		3.02%	← 29 Year Amortization →			
395.00 Laboratory Equipment	33.30		2.41%	← 40 Year Amortization →			
397.CE Communication Equipment	17.60		4.13%	← 23 Year Amortization →			
398.00 Miscellaneous Equipment	11.60		5.45%	← 18 Year Amortization →			
Total Amortizable			5.10%	11.20		41.95%	3.65%
Total General Plant			8.97%	6.21	-4.7%	46.29%	7.31%
TOTAL UTILITY			4.53%	14.29	-4.7%	43.58%	4.14%

UNS ELECTRIC, INC. Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
Depreciable				
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$103,906	$111,378	$7,472
Total Depreciable	$3,558,415	$103,906	$111,378	$7,472
Amortizable				
302.00 Franchises and Consents	$11,908		$54	$54
303.00 Miscellaneous Intangible Plant	4,219,098		141,762	141,762
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	69,591	73,298	3,707
303.PC Misc.Intangible Plant - PC Software	1,145,223	229,045	1,145	(227,900)
Total Amortizable	$7,061,229	$298,636	$216,259	($82,377)
Total Intangible Plant	$10,619,644	$402,542	$327,637	($74,905)
OTHER PRODUCTION PLANT				
341.00 Structures and Improvements	$619,244	$8,546	$12,756	$4,210
342.00 Fuel Holders, Producers and Accessories	631,364	15,279	15,847	568
343.00 Prime Movers	8,684,079	203,207	218,839	15,632
344.00 Generators	2,309,132	15,471	53,803	38,332
345.00 Accessory Electric Equipment	1,685,197	37,074	39,434	2,360
346.00 Miscellaneous Power Plant Equipment	493,979	9,237	13,041	3,804
Total Other Production Plant	$14,422,995	$288,814	$353,720	$64,906
TRANSMISSION PLANT				
350.RW Rights of Way	$346,016		$6,990	$6,990
352.00 Structures and Improvements	191,668	7,226	5,961	(1,265)
353.00 Station Equipment	17,657,646	515,603	556,216	40,613
354.00 Towers and Fixtures	521,825	21,290	26,196	4,906
355.00 Poles and Fixtures	12,285,169	708,854	549,147	(159,707)
356.00 Overhead Conductors and Devices	11,245,657	304,757	299,134	(5,623)
359.00 Roads and Trails	183,860	3,696	3,696	
Total Transmission Plant	$42,431,841	$1,561,426	$1,447,340	($114,086)
DISTRIBUTION PLANT				
360.RW Rights of Way	$86,619		$1,758	$1,758
361.00 Structures and Improvements	3,398,247	108,744	100,588	(8,156)
362.00 Station Equipment	28,402,465	1,368,999	1,158,821	(210,178)
364.00 Poles, Towers and Fixtures	75,596,882	3,197,748	3,122,151	(75,597)
365.00 Overhead Conductors and Devices	48,310,770	2,106,350	1,990,404	(115,946)
366.00 Underground Conduit	12,126,868	519,030	458,396	(60,634)
367.00 Underground Conductors and Devices	22,976,392	1,231,535	1,008,664	(222,871)
368.00 Line Transformers	45,658,424	2,250,960	2,109,419	(141,541)
369.OH Services - Overhead	7,297,945	308,703	274,403	(34,300)
369.UG Services - Underground	3,315,090	140,228	123,984	(16,244)
370.00 Meters	9,368,222	304,467	290,415	(14,052)
373.00 Street Lighting and Signal Systems	3,769,729	171,523	151,920	(19,603)
Total Distribution Plant	$260,307,653	$11,708,287	$10,790,923	($917,364)

UNS ELECTRIC, INC.

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	2006 Annualized Accrual Proposed	2006 Annualized Accrual Difference
A	B	C	D	E=D-C
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$2,445,738	$70,682	$64,567	($6,115)
392.C1 Transportation Equipment - Class 1	366,331	91,583	42,055	(49,528)
392.C2 Transportation Equipment - Class 2	882,290	220,573	134,902	(85,671)
392.C3 Transportation Equipment - Class 3	1,007,316	251,829	188,267	(63,562)
392.C4 Transportation Equipment - Class 4	4,808,218	601,027	575,544	(25,483)
392.C5 Transportation Equipment - Class 5	584,467	73,058	65,986	(7,072)
396.00 Power Operated Equipment	968,258	32,243	66,519	34,276
Total Depreciable	$11,062,618	$1,340,995	$1,137,840	($203,155)
Amortizable				
391.10 Office Furniture and Equipment	$2,297,349	$85,461	$103,610	$18,149
391.20 Computer Equipment - PCs	868,777	173,755	15,030	(158,725)
393.00 Stores Equipment	122,871	3,219	3,698	479
394.00 Tools, Shop and Garage Equipment	2,391,755	72,231	79,406	7,175
395.00 Laboratory Equipment	808,108	19,475	20,203	728
397.CE Communication Equipment	2,391,716	98,778	100,691	1,913
398.00 Miscellaneous Equipment	114,643	6,248	5,893	(355)
Total Amortizable	$8,995,219	$459,167	$328,531	($130,636)
Total General Plant	$20,057,837	$1,800,162	$1,466,371	($333,791)
TOTAL UTILITY	$347,839,970	$15,761,231	$14,385,991	($1,375,240)

UNS ELECTRIC, INC.

Statement C

Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415	$238,117	6.69%	$204,609	5.75%	$201,261	5.66%
Total Depreciable	$3,558,415	$238,117	6.69%	$204,609	5.75%	$201,261	5.66%
Amortizable							
302.00 Franchises and Consents	$11,908	$0		$11,775	98.88%	$11,775	98.88%
303.00 Miscellaneous Intangible Plant	4,219,098	267,350	6.34%	2,971,824	70.44%	2,971,824	70.44%
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	159,478	9.46%	183,152	10.87%	183,152	10.87%
303.PC Misc.Intangible Plant - PC Software	1,145,223	1,178,678	102.92%	1,144,041	99.90%	1,144,041	99.90%
Total Amortizable	$7,061,229	$1,605,507	22.74%	$4,310,792	61.05%	$4,310,792	61.05%
Total Intangible Plant	$10,619,644	$1,843,624	17.36%	$4,515,401	42.52%	$4,512,053	42.49%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	$619,244	$367,625	59.37%	$246,434	39.80%	$242,402	39.14%
342.00 Fuel Holders, Producers and Accessories	631,364	121,053	19.17%	116,329	18.43%	114,426	18.12%
343.00 Prime Movers	8,684,079	2,637,958	30.38%	3,002,520	34.58%	2,953,395	34.01%
344.00 Generators	2,309,132	254,855	11.04%	367,850	15.93%	361,832	15.67%
345.00 Accessory Electric Equipment	1,685,197	450,671	26.74%	533,384	31.65%	524,658	31.13%
346.00 Miscellaneous Power Plant Equipment	493,979	71,873	14.55%	60,577	12.26%	59,586	12.06%
Total Other Production Plant	$14,422,995	$3,904,034	27.07%	$4,327,095	30.00%	$4,256,297	29.51%
TRANSMISSION PLANT							
350.RW Rights of Way	$346,016	$1		$129,064	37.30%	$126,952	36.69%
352.00 Structures and Improvements	191,668	147,919	77.17%	117,614	61.36%	115,690	60.36%
353.00 Station Equipment	17,657,646	6,525,850	36.96%	5,672,519	32.13%	5,579,708	31.60%
354.00 Towers and Fixtures	521,825	144,146	27.62%	106,452	20.40%	104,711	20.07%
355.00 Poles and Fixtures	12,285,169	6,414,872	52.22%	6,665,775	54.26%	6,556,714	53.37%
356.00 Overhead Conductors and Devices	11,245,657	4,276,151	38.02%	4,187,528	37.24%	4,119,014	36.63%
359.00 Roads and Trails	183,860	73,249	39.84%	54,496	29.64%	53,604	29.16%
Total Transmission Plant	$42,431,841	$17,582,187	41.44%	$16,933,449	39.91%	$16,656,393	39.25%
DISTRIBUTION PLANT							
360.RW Rights of Way	$86,619	$0		$38,615	44.58%	$37,983	43.85%
361.00 Structures and Improvements	3,398,247	824,191	24.25%	845,564	24.88%	831,729	24.48%
362.00 Station Equipment	28,402,465	14,346,966	50.51%	15,291,887	53.84%	15,041,690	52.96%

UNS ELECTRIC, INC.
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
364.00 Poles, Towers and Fixtures	75,596,882	35,977,383	47.59%	37,523,576	49.64%	36,909,637	48.82%
365.00 Overhead Conductors and Devices	48,310,770	22,914,406	47.43%	23,357,935	48.35%	22,975,766	47.56%
366.00 Underground Conduit	12,126,868	4,060,572	33.48%	4,247,436	35.03%	4,177,941	34.45%
367.00 Underground Conductors and Devices	22,976,392	9,724,089	42.32%	8,790,967	38.26%	8,647,135	37.63%
368.00 Line Transformers	45,658,424	21,572,430	47.25%	19,885,236	43.55%	19,559,885	42.84%
369.OH Services - Overhead	7,297,945	3,359,775	46.04%	3,397,599	46.56%	3,342,009	45.79%
369.UG Services - Underground	3,315,090	1,044,451	31.51%	1,318,669	39.78%	1,297,094	39.13%
370.00 Meters	9,368,222	2,871,949	30.66%	2,865,926	30.59%	2,819,036	30.09%
373.00 Street Lighting and Signal Systems	3,769,729	1,250,480	33.17%	1,260,597	33.44%	1,239,972	32.89%
Total Distribution Plant	$260,307,653	$117,946,692	45.31%	$118,824,008	45.65%	$116,879,878	44.90%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$2,445,738	$800,583	32.73%	$577,323	23.61%	$567,877	23.22%
392.C1 Transportation Equipment - Class 1	366,331	274,470	74.92%	164,116	44.80%	161,431	44.07%
392.C2 Transportation Equipment - Class 2	882,290	615,312	69.74%	393,051	44.55%	386,620	43.82%
392.C3 Transportation Equipment - Class 3	1,007,316	706,361	70.12%	294,023	29.19%	289,213	28.71%
392.C4 Transportation Equipment - Class 4	4,808,218	4,578,490	95.22%	3,445,689	71.66%	3,389,313	70.49%
392.C5 Transportation Equipment - Class 5	584,467	95,384	16.32%	93,369	15.98%	91,841	15.71%
396.00 Power Operated Equipment	968,258	732,737	75.68%	635,177	65.60%	624,785	64.53%
Total Depreciable	$11,062,618	$7,803,339	70.54%	$5,602,749	50.65%	$5,511,080	49.82%
Amortizable							
391.10 Office Furniture and Equipment	$2,297,349	$764,125	33.26%	$912,876	39.74%	$912,876	39.74%
391.20 Computer Equipment - PCs	868,777	62,880	7.24%	851,825	98.05%	851,825	98.05%
393.00 Stores Equipment	122,871	57,010	46.40%	68,689	55.90%	68,689	55.90%
394.00 Tools, Shop and Garage Equipment	2,391,755	950,482	39.74%	1,096,139	45.83%	1,096,139	45.83%
395.00 Laboratory Equipment	808,108	198,068	24.51%	286,621	35.47%	286,621	35.47%
397.CE Communication Equipment	2,391,716	387,217	16.19%	473,306	19.79%	473,306	19.79%
398.00 Miscellaneous Equipment	114,643	89,560	78.12%	84,062	73.33%	84,062	73.33%
Total Amortizable	$8,995,219	$2,509,343	27.90%	$3,773,518	41.95%	$3,773,518	41.95%
Total General Plant	$20,057,837	$10,312,681	51.41%	$9,376,267	46.75%	$9,284,598	46.29%
TOTAL UTILITY	$347,839,970	$151,589,220	43.58%	$153,976,220	44.27%	$151,589,220	43.58%

UNS ELECTRIC, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Retirements	Survivors	Salvage Rate Realized	Future	Net Salvage Realized	Future	Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
Depreciable									
303.WP Misc. Intangible - WAPA Switchboard	$3,558,415		$3,558,415						
Total Depreciable	$3,558,415		$3,558,415						
Amortizable									
302.00 Franchises and Consents	$11,908		$11,908						
303.00 Miscellaneous Intangible Plant	4,219,099	1	4,219,098						
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC Misc.Intangible Plant - PC Software	1,145,223		1,145,223						
Total Amortizable	$7,061,230	$1	$7,061,229						
Total Intangible Plant	$10,619,645	$1	$10,619,644						
OTHER PRODUCTION PLANT									
341.00 Structures and Improvements	$619,244		$619,244						
342.00 Fuel Holders, Producers and Accessories	631,364		631,364						
343.00 Prime Movers	10,707,541	2,023,462	8,684,079						
344.00 Generators	2,356,732	47,600	2,309,132						
345.00 Accessory Electric Equipment	1,904,534	219,337	1,685,197						
346.00 Miscellaneous Power Plant Equipment	503,598	9,619	493,979						
Total Other Production Plant	$16,723,013	$2,300,018	$14,422,995						
TRANSMISSION PLANT									
350.RW Rights of Way	$346,016		$346,016						
352.00 Structures and Improvements	191,668		191,668						
353.00 Station Equipment	17,697,125	39,479	17,657,646						
354.00 Towers and Fixtures	521,825		521,825						
355.00 Poles and Fixtures	12,393,414	108,245	12,285,169		-10.0%		(1,228,517)	(1,228,517)	-9.9%
356.00 Overhead Conductors and Devices	11,267,316	21,659	11,245,657						
359.00 Roads and Trails	183,860		183,860						
Total Transmission Plant	$42,601,224	$169,383	$42,431,841		-2.9%		($1,228,517)	($1,228,517)	-2.9%
DISTRIBUTION PLANT									
360.RW Rights of Way	$86,619		$86,619						
361.00 Structures and Improvements	3,409,388	11,141	3,398,247						
362.00 Station Equipment	28,425,896	23,431	28,402,465						
364.00 Poles, Towers and Fixtures	76,698,662	1,101,780	75,596,882	-0.8%	-10.0%	(8,814)	(7,559,688)	(7,568,502)	-9.9%
365.00 Overhead Conductors and Devices	49,287,987	977,217	48,310,770	-1.8%	-10.0%	(17,590)	(4,831,077)	(4,848,667)	-9.8%
366.00 Underground Conduit	12,235,191	108,323	12,126,868	0.1%	-5.0%	108	(606,343)	(606,235)	-5.0%
367.00 Underground Conductors and Devices	23,284,235	307,643	22,976,392	-0.8%		(2,463)		(2,463)	
368.00 Line Transformers	47,077,581	1,419,157	45,658,424	-5.9%	-5.0%	(83,730)	(2,282,921)	(2,366,651)	-5.0%
369.OH Services - Overhead	7,297,945		7,297,945						
369.UG Services - Underground	3,315,090		3,315,090						
370.00 Meters	9,760,332	392,110	9,368,222		-5.0%		(468,411)	(468,411)	-4.8%
373.00 Street Lighting and Signal Systems	3,640,377	70,648	3,769,729						
Total Distribution Plant	$264,719,303	$4,411,650	$260,307,653	-2.5%	-6.0%	($112,489)	($15,748,441)	($15,860,930)	-6.0%

6/5/2007

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UNS ELECTRIC, INC.
Average Net Salvage

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$2,445,743	$5	$2,445,738						
392.C1 Transportation Equipment - Class 1	456,297	89,966	366,331	8.0%	10.0%	7,197	36,633	43,830	9.6%
392.C2 Transportation Equipment - Class 2	1,163,990	301,700	882,290	9.0%	10.0%	27,153	88,229	115,362	9.7%
392.C3 Transportation Equipment - Class 3	1,802,214	794,898	1,007,316	3.9%	10.0%	31,001	100,732	131,733	7.3%
392.C4 Transportation Equipment - Class 4	4,853,150	44,932	4,808,218	12.9%	10.0%	5,796	480,822	486,618	10.0%
392.C5 Transportation Equipment - Class 5	584,467		584,467		10.0%		58,447	58,447	10.0%
398.00 Power Operated Equipment	968,258		968,258						
Total Depreciable	$12,294,119	$1,231,501	$11,062,618	5.8%	6.9%	$71,148	$764,862	$836,010	6.8%
Amortizable									
391.10 Office Furniture and Equipment	$5,955,915	$3,658,566	$2,297,349						
391.20 Computer Equipment - PCs	868,777		868,777						
393.00 Stores Equipment	122,871		122,871						
394.00 Tools, Shop and Garage Equipment	2,455,025	63,270	2,391,755						
395.00 Laboratory Equipment	864,222	56,114	808,108						
397.CE Communication Equipment	2,432,124	40,408	2,391,718						
398.00 Miscellaneous Equipment	114,643		114,643						
Total Amortizable	$12,813,577	$3,818,358	$8,995,219						
Total General Plant	$25,107,696	$5,049,859	$20,057,837	1.4%	3.8%	$71,148	$764,862	$836,010	3.3%
TOTAL UTILITY	$359,770,881	$11,930,911	$347,839,970	-0.3%	-4.7%	($41,341)	($16,212,096)	($16,253,437)	-4.5%

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Account Description	Present Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc. Intangible - WAPA Switchboard	49.00	S6	49.00	38.00			32.00	R1	32.00	30.16		
Total Depreciable									32.00	30.16		
Amortizable												
302.00 Franchises and Consents	49.00	S6	49.00	38.00			25.00	SQ	25.00	2.50		
303.00 Miscellaneous Intangible Plant	40.00	S4	40.00	38.20			15.00	SQ	15.00	8.81		
303.WO Misc. Intangible - WAPA Fiber Optic	40.00	S4	40.00	38.20			23.00	SQ	23.00	20.50		
303.PC Misc.Intangible Plant - PC Software	36.00	R1	36.00	31.00			5.00	SQ	5.00	1.00		
Total Amortizable									12.09	7.21		
Total Intangible Plant									15.27	10.88		
OTHER PRODUCTION PLANT												
341.00 Structures and Improvements	49.00	S6	49.00	38.00			49.00	S6	49.00	29.50		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	38.20			40.00	S4	40.00	32.63		
343.00 Prime Movers	40.00	R3	40.00	37.00			40.00	R3	40.00	26.17		
344.00 Generators	43.00	S0	43.00	22.60			43.00	S0	43.00	36.15		
345.00 Accessory Electric Equipment	43.00	S6	43.00	39.50			43.00	S6	43.00	29.39		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	36.00	31.00			38.00	R1	38.00	33.34		
Total Other Production Plant									41.04	28.73		
TRANSMISSION PLANT												
350.RW Rights of Way							50.00	SQ	50.00	31.35		
352.00 Structures and Improvements	33.00	R3	33.00	19.70			33.00	R3	33.00	12.75		
353.00 Station Equipment	32.00	R1	32.00	23.00			32.00	R1	32.00	21.72		
354.00 Towers and Fixtures	20.00	L0	20.00	12.40			20.00	L0	20.00	15.92		
355.00 Poles and Fixtures	25.00	S5	25.00	15.90	-10.0	-10.0	25.00	S5	25.00	12.68	-9.9	-10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	30.10			38.00	L3	38.00	23.85		
359.00 Roads and Trails	50.00	SQ	50.00	44.90			50.00	SQ	50.00	35.18		
Total Transmission Plant									30.71	18.90	-2.9	-2.9
DISTRIBUTION PLANT												
360.RW Rights of Way							50.00	SQ	50.00	27.71		
361.00 Structures and Improvements	34.00	R4	34.00	23.60			34.00	R4	34.00	25.54		
362.00 Station Equipment	25.00	S4	25.00	15.30			25.00	S4	25.00	11.54		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	18.90	-10.0	-10.0	27.00	S4	27.00	14.83	-9.9	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	18.40	-10.0	-10.0	27.00	S3	27.00	15.16	-9.8	-10.0

Statement E

UNS ELECTRIC, INC.
Present and Proposed Parameters
Broad Group Procedure

Account Description	Present Parameters						Proposed Parameters					
	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
366.00 Underground Conduit	28.00	S2	26.00	21.50			28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.30			23.00	S3	23.00	14.20		
368.00 Line Transformers	23.00	S4	23.00	14.20	-5.0	-5.0	23.00	S4	23.00	13.46	-5.0	-5.0
369.OH Services - Overhead	27.00	R5	27.00	18.30			27.00	R5	27.00	14.43		
369.UG Services - Underground	27.00	R5	27.00	18.30			27.00	R5	27.00	16.26		
370.00 Meters	34.00	R3	34.00	26.20	-5.0	-5.0	34.00	R3	34.00	24.14	-4.8	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	17.40			25.00	S4	25.00	16.64		
Total Distribution Plant									25.87	14.75	-6.0	-6.0
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	36.00	27.80			38.00	R2	38.00	29.03		
392.C1 Transportation Equipment - Class 1							8.00	L1.5	8.00	4.00	9.6	10.0
392.C2 Transportation Equipment - Class 2							6.00	L2	6.00	3.02	9.7	10.0
392.C3 Transportation Equipment - Class 3							5.00	S5	5.00	3.28	7.3	10.0
392.C4 Transportation Equipment - Class 4							8.00	S4	8.00	1.63	10.0	10.0
392.C5 Transportation Equipment - Class 5							8.00	S4	8.00	6.58	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	6.80			15.00	S5	15.00	5.16		
Total Depreciable									9.24	4.13	6.8	6.9
Amortizable												
391.10 Office Furniture and Equipment	21.00	R2	21.00	17.60			21.00	SQ	21.00	13.37		
391.20 Computer Equipment - PCs	5.00		5.00				5.00	SQ	5.00	1.13		
393.00 Stores Equipment	33.00	S6	33.00	28.10			33.00	SQ	33.00	14.67		
394.00 Tools, Shop and Garage Equipment	29.00	S-.5	29.00	23.80			29.00	SQ	29.00	16.32		
395.00 Laboratory Equipment	40.00	R4	40.00	33.30			40.00	SQ	40.00	25.85		
397.CE Communication Equipment	23.00	R1.5	23.00	17.60			23.00	SQ	23.00	19.07		
398.00 Miscellaneous Equipment	18.00	R4	18.00	11.60			18.00	SQ	18.00	5.19		
Total Amortizable									17.99	11.20		
Total General Plant									11.82	6.21	-4.5	-4.7
TOTAL UTILITY									24.51	14.29	-4.5	-4.7

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. G-04204A-06-____

Direct Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

December 15, 2006

EXHIBIT
UNSE 34

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP") as General Manager, Financial Planning and Customer Pricing. In this role I am responsible for providing financial and regulatory support services to UniSource Energy Corporation ("UniSource Energy"), and its regulated utility subsidiaries UNS Gas, Inc. ("UNS Gas"), UNS Electric, Inc. ("UNS Electric") and TEP.

Q. Please summarize your professional experience and education.

A. My educational achievements include a Master of Business Administration degree with a concentration in finance from the University of Texas at Austin, as well as a Bachelor of Science degree in Civil Engineering from Purdue University. I am a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA. I am also a member of the Society of Utility and Regulatory Financial Analysts, and in 1992, I was awarded the designation of Certified Rate of Return Analyst ("CRRA").

From 1984 to 1995, I was employed by the Public Utility Commission of Texas. During this period I served in various staff positions, including Director of the Financial Review Division. In that role I directed a staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities.

As a staff member I provided expert testimony on a variety of financial topics including the cost of capital.

I joined TEP in 1995 as a senior financial analyst. In 1997, I was promoted to Director of Capital Resources and elected Assistant Treasurer. I was subsequently promoted to Manager of Financial Planning and in 2003, became a General Manager in TEP's Shared Services Unit. In these roles I have gained additional experience in financial forecasting, financial analysis, the structuring of new financings and other related activities.

Q. What is the purpose of your direct testimony?

A. In my direct testimony I support UNS Electric's request for a rate increase by: (i) providing an overview of the Company's financial condition; (ii) recommending a fair rate of return on common equity capital; (iii) presenting UNS Electric's weighted average cost of capital; (iv) describing the financial impact of UNS Electric's requested rate relief; and (v) explaining why it is important for the Arizona Corporation Commission ("Commission") to include construction work-in-progress ("CWIP") in UNS Electric's rate base. In my testimony, I also make a recommendation concerning the appropriate interest rate to use in calculating carrying costs on deferred fuel and purchased power costs. Finally, I am sponsoring Schedule A-3 (Summary Capital Structure), Schedule A-4 (Construction Expenditures and Gross Plant in Service), the "D" Schedules (Cost of Capital Information) and the "F" Schedules (Projections and Forecasts) in support of UNS Electric's request for a rate increase.

Q. Please summarize the recommended fair rate of return, weighted average cost of capital, cost of debt and return on common equity UNS Electric is utilizing in this rate request.

A. The Company's rate request reflects an overall rate of return and weighted average cost of capital of 9.89%. This overall rate of return is based on an 11.8% cost of common equity capital, an 8.22% cost of long-term debt and a 6.36% cost of short-term debt, with a capital structure consisting of 48.85% common equity, 47.18% long-term debt and 3.97% short-term debt. This reflects UNS Electric's actual capital structure as of June 30, 2006. The requested rate of return on fair value rate base is 7.84%.

II. <u>FINANCIAL CONDITION OF UNS ELECTRIC.</u>

Q. Please describe UNS Electric's current financial condition.

A. UNS Electric has a mixed financial profile. On the positive side, the Company has a healthy mix of debt and equity capital and a growing service area. However, these strengths are offset by weak operating cash flows and large construction spending needs due to rapid growth in UNS Electric's service territory. This gap between internal cash flow and capital spending creates a substantial need for new capital. In addition to financing capital expenditures for the Company's transmission and distribution system, UNS Electric will also have to refinance $60 million of long-term notes maturing in August 2008 and acquire new energy resources to replace the Company's current full-requirements contract by June 2008. Obviously, it is critical that UNS Electric has the financial resources necessary to meet the infrastructure and energy supply needs of its customers. UNS Electric's requested rate increase is necessary to meet those needs.

Q. Has the Company's financial condition improved since UniSource Energy acquired the electric utility operations from Citizens Communications Company ("Citizens") in 2003?

A. The Company's financial condition has improved in certain respects but weakened in other respects. On the positive side, the Company's equity ratio (equity / total capitalization) has improved from 36% in August of 2003 to 49% at the end of the test year. This has been accomplished through the retention of 100% of annual earnings at UNS Electric and additional equity contributions of $14 million made by UniSource Energy. The Company's short-term liquidity was also significantly enhanced through the establishment of a revolving credit facility, shared with UNS Gas, which was recently expanded to $60 million (pending Commission approval in Docket No. E-04204A-06-0493). As amended, this facility would allow either UNS Electric or UNS Gas to borrow a maximum of $45 million under the facility at any given time. However, since the acquisition was completed, the Company's net cash flow has declined significantly. The following table highlights the some of the key financial results from 2004 and 2005, the first two fiscal years following the acquisition, and forecasted financial results for 2006 and 2007:

($000s)	2004 Actual	2005 Actual	2006 Fcst.	2007 Fcst.
Net Income	$4,338	$4,994	$3,882	$1,720
Return on Avg. Equity	11.2%	11.0%	6.8%	2.5%
Operating Cash Flow (a)	$18,558	$20,537	$10,346	$11,733
Capital Expenditures (b)	$19,005	$29,951	$39,280	$42,864
Net Cash Flow [(a) – (b)]	($447)	($9,414)	($28,934)	($31,131)

Q. Are the debt obligations of UNS Electric rated by the major credit rating agencies?

A. No. Credit ratings assigned by Moody's, Standard & Poor's and Fitch were not required by the lenders to UNS Electric. However, the lenders who purchased $60 million of long-term notes from UNS Electric in 2003 did require a rating from the National Association of Insurance Commissioners ("NAIC"). The rating assigned to these notes was NAIC-3, which is roughly equivalent to a speculative-grade credit rating of Ba from Moody's or BB from Standard & Poor's or Fitch. This rating was one grade lower than the NAIC-2 investment-grade rating assigned to UNS Gas. The primary factor contributing to a lower rating at UNS Electric was the projected gap between operating cash flows and capital spending needs. As a result of this lower rating, the long-term notes issued by UNS Electric carry a higher interest rate of 7.61% and have a shorter five-year term relative to the notes issued by UNS Gas, which carry an interest rate of 6.23% and have an average term of ten years.

Q. If UNS Electric were to seek credit ratings from the major credit rating agencies, would the Company's debt obligations be rated investment grade?

A. No, it is highly unlikely that UNS Electric would receive investment grade credit ratings at this time. Although the Company has a healthy mix of debt and equity capital, UNS Electric's cash flow and earnings are both forecasted to decline significantly through 2007. Until the Company receives adequate rate relief, and additional resources are procured to meet retail load in 2008 and beyond, it would be premature for UNS Electric to approach the rating agencies with an expectation of receiving investment grade credit ratings.

Q. How does UNS Electric's financial condition compare with other electric utilities?

A. The Company's 11.0% return on average common equity in 2005 was comparable to average returns for the industry. On a composite basis, the average annual return on common equity reported by Value Line for the electric utility industry ranged from 10.5% to 12.1% over the period 2003-2005. However, the forecasted 6.8% return on common equity for UNS Electric in 2006 is substantially below industry norms. In terms of debt leverage, the ratio of total debt to total capital exceeded the industry median value at year-end 2005 but has since improved due to capital contributions made by UniSource Energy. In terms of cash flow, UNS Electric lagged behind the industry by a considerable margin in 2005. On two key cash flow ratios – Funds from Operations ("FFO") Interest Coverage and Net Cash Flow to Capital Expenditures -- UNS Electric's performance was significantly below the median value for a group of 31 electric distribution companies rated by Fitch Ratings service. The credit ratings for this group ranged from a low of BB+ to a high of A+, with a median credit rating of BBB. The following table compares the key credit quality metrics for UNS Electric (2005 actual and 2006 projected values) with the industry median values for electric distribution companies:

	2005 Actual	2006 Forecast	Industry Median
FFO Interest Coverage	3.1X	3.0X	4.3X
FFO to Total Debt	19%	16%	22%
Net Cash Flow / Capital Expenditures	69%	26%	86%
Total Debt / Total Capital	57%	56%	48%

Net Cash Flow = Operating Cash Flow less Dividends Paid.

The gap between UNS Electric and the industry median value for Net Cash Flow / Capital Expenditures is of particular concern for two reasons. First, a ratio of less than 100% indicates a dependence on outside capital to fund ongoing capital expenditures. During 2005 and the first half of 2006, most of this gap was funded through increased equity contributions by UniSource Energy. These contributions were made despite a forecasted reduction in earnings at UNS Electric and in the absence of any common dividend payout from UNS Electric. Reliance on the Company's other source of capital, borrowed funds, is also constrained due to financial covenants contained in the Company's credit agreements and by the need to improve UNS Electric's credit profile. Absent a significant increase in operating cash flow, it will be difficult for the Company to attract the capital needed to fund required capital expenditures. Second, the gap between UNS Electric and the industry median value is actually much larger than indicated in the table above when dividend payout policies are considered. The average dividend payout as a percentage of earnings for the electric utility industry was 57% as reported by Value Line for 2005. Had UNS Electric paid out common dividends in 2005 at the industry average payout rate of 57%, the Company's ratio of Net Cash Flow / Capital Expenditures would have fallen from 69% to 59%.

III. COST OF CAPITAL METHODOLOGY.

Q. Please describe the methodology you have used to determine a recommended rate of return for UNS Electric.

A. I have employed the weighted average cost of capital methodology. There are three basic steps in calculating the weighted average cost of capital. First, it is necessary to analyze the firm's capital structure, identify the sources of capital, and determine the appropriate weighting for each source of capital. For UNS Electric, these sources consist of long-term debt, short-term debt and common equity capital. Second, the appropriate cost of each component of the capital structure must be determined. For long-term debt, it is customary for rate setting purposes to use the embedded cost of debt. For short-term variable rate debt, it is appropriate to use either the current spot interest rate or a forecast based on forward market interest rates. For common equity, a variety of techniques are available to estimate the cost of this capital. Finally, the cost of each capital source is weighted by its appropriate percentage share of the capital structure. The sum of the weighted component costs represents the weighted average cost of capital. The calculation of UNS Electric's weighted average cost of capital is provided in Section VIII of my testimony. This recommended value, 9.89%, is also reflected in Schedule D-1 in the Company's rate filing.

IV. CAPITAL STRUCTURE.

Q. Please describe the capital structure for UNS Electric as of the end of the test year.

A. The capital structure for UNS Electric as of June 30, 2006 consisted of $61.6 million of common equity and $60 million principal amount of long-term debt. After adjusting for unamortized issuance expenses, the long-term debt balance as of June 30, 2006 was $59.5 million. Additionally, the Company had $5 million outstanding under its revolving credit facility. As reflected in the following table, long-term and short-term debt comprised approximately 51% of total capital whereas common equity represented approximately 49% of total capital:

	6/30/06 ($thousands)	% of Total
Common Equity	$61,587	48.85%
Long-Term Debt	59,486	47.18%
Short-Term Debt	5,000	3.97%
Total Capital	$126,073	100.00%

This test year capital structure excludes the $394,000 balance of capital lease obligations at June 30, 2006. These capital lease obligations are instead reflected as operating expenses in UNS Electric's proposed revenue requirement. Short-term debt has been included in the test year capital structure since UNS Electric will likely continue to carry a revolving credit loan balance.

Q. Do you recommend that this capital structure be adopted for rate setting purposes?

A. Yes. This capital structure is in line with industry norms, and represents a reasonable target for the Company to maintain over the long-run. As discussed previously, the median ratio of debt to total capital for a group of 31 electric distribution companies rated by Fitch was 48%. The recommended capital structure for UNS Electric contains approximately 51% debt, an amount only slightly higher than the industry median value.

V. COST OF COMMON EQUITY CAPITAL.

Q. Please provide an overview of the methodology used to estimate the cost of equity capital for UNS Electric.

A. We employed four stages of analysis to derive an estimated cost of equity for UNS Electric. First, the estimated cost of equity for a group of comparable companies was determined. Using the discounted cash flow approach ("DCF") and the capital asset pricing model ("CAPM"), we developed a range for the cost of equity. Second, we examined the risk profile of UNS Electric relative to the comparable company group in order to determine an appropriate range and point estimate for the Company's cost of equity. Third, the estimated cost of equity determined for UNS Electric was compared with the allowed returns on equity for other electric utilities in the United States. Based on a review of this data, and the relationship between allowed returns on equity and long-term interest rates, we were able to confirm the reasonableness of our cost of equity estimate for UNS Electric. Finally, we examined the financial impact of the recommended return on equity ("ROE") and the overall rate request on UNS Electric. This final step was taken in order to assess the Company's ability to attract capital on reasonable terms, a key objective to consider in setting the allowed rate of return for a regulated utility.

A. Comparable Company Group.

Q. Why did you analyze a group of comparable companies in order to estimate the cost of equity capital for UNS Electric?

A. Reliance on a comparable company analysis is important because UNS Electric does not have publicly traded equity securities. Additionally, the assets of UniSource Energy, the parent company of UNS Electric, are heavily weighted toward TEP. Although the risk profiles of UNS Electric and TEP are somewhat similar, TEP has a much larger investment in generating facilities and a case pending before the Commission regarding the deregulated status of those facilities. As a consequence, the cost of equity capital for UniSource Energy or TEP may not be representative of the cost of equity capital for UNS Electric.

Q. What criteria did you employ in selecting companies for the comparable company analysis?

A. As a starting point we considered each of the companies included in the electric utility industry by Value Line Investment Survey ("Value Line"). From this group of approximately 60 companies we then selected eight companies that met the following screening criteria:

(i) Emphasis on electric utility operations, with more than 50% of total gross plant used for electric operations,

(ii) Emphasis on electric distribution operations, with at least 40% of net electric plant investment in transmission and distribution assets, and at least 30% of electric energy requirements met through purchased power,

(iii) Emphasis on retail utility service, with more than 50% of revenues derived from retail electric and gas sales,

(iv) No pending mergers or acquisitions of any significance,

(v) Market capitalization of $5 billion or less, and

(vi) Common stock currently paying a dividend.

Exhibit KCG-1 provides summary information on each of the companies that were selected based on these criteria. Although each of these companies may have unique circumstances that would differentiate them from UNS Electric, as a group these companies have operating and financial characteristics similar to those of UNS Electric. The extent of this similarity is discussed further in Section VI of my testimony.

B. Application of DCF Model.

Q. Please explain the DCF methodology.

A. The DCF methodology is derived from the Gordon dividend growth model. In its original form, the Gordon growth model may be used as a tool for determining the value of a share of common stock. The theory holds that the price of a share is equal to the present value of all future dividends. It is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+k_1)^1} + \frac{D_2}{(1+k_2)^2} + \ldots + \frac{D_n}{(1+k_n)^n}$$

Where: P_0 = Current share price
D_n = Expected dividend in each year
k_n = Investors required rate of return in each year
n = One to infinity

If the dividends are assumed to grow at a constant rate "g" into the future, the required rate of return "k" is assumed to be constant from year to year, and "k" is greater than "g", then the equation above reduces to the following form as "n" approaches infinity:

$$P_0 = \frac{D_1}{(k - g)}$$

For purposes of estimating the cost of common equity capital, the equation above may be rearranged to solve for the investor's required rate of return:

$$k = \frac{D_1}{P_0} + g$$

Essentially, the constant growth DCF model recognizes that the return to the stockholder consists of two parts: dividend yield and growth. Equity investors expect to receive a portion of their total required return in the form of current dividends and the remainder though price appreciation. Unfortunately, the constant growth DCF model cannot be applied to companies having expected near-term growth rates that are significantly higher or lower than their long-term growth potential. In other words, the "g" variable is not expected to remain constant over time. In these situations, it is usually necessary to apply a multi-stage DCF model which incorporates the various growth rates expected over time.

Q. Please describe the multi-stage DCF model.

A. If the Gordon dividend growth model is modified to reflect the expected future price of the stock in terminal year "n", and assuming that the investor's required rate of return "k" is constant, the current value of a stock may be derived from the following equation:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n}$$

Where: P_0 = Current share price
D_n = Expected dividend in each year
P_n = Expected share price in year "n"
n = Year of expected share price

If the expected growth rate "g" is constant beyond year "n", the expected value of "P_n" can be obtained from the constant growth DCF model:

$$P_n = \frac{D_n (1 + g)}{(k - g)}$$

Substituting this equation for "P_n" in the modified Gordon growth model, the following multi-stage DCF equation is obtained:

$$P_0 = \frac{D_1}{(1 + k)^1} + \frac{D_2}{(1 + k)^2} + \ldots + \frac{D_n}{(1 + k)^n} + \frac{D_n (1 + g)}{(k - g)(1 + k)^n}$$

Using this equation, the current share price, and the expected values for D_1 through D_n and "g", the required rate of return "k" may be calculated using an iterative solution process. The discount rate "k" which equates the current share price with the present value of future expected dividends represents the investor's required rate of return.

Q. How did you determine near-term dividend growth rates for each of the comparable companies?

A. We relied on estimates of future dividends and earnings growth published by Value Line, Thomson Financial Network ("Thomson"), Zacks Investment Research ("Zacks") and SNL Financial ("SNL"). These estimates are all widely available in the investment community and are superior to estimates based solely on historical trend analysis. Published estimates are inherently forward-looking, and presumably take into account historical financial trends as well as any future threats and opportunities.

Q. What specific growth rates did you select for each company?

A. Exhibit KCG-2 provides the range of growth estimates for each company, as well as the five-year growth rate selected for use in the multi-stage DCF model. The growth rates from Value Line were derived using the published point estimates for dividends per share ("DPS") and earnings per share ("EPS") for the 2009-2011 timeframe. The five-year EPS projections from Thomson, Zacks and SNL represent the median or "consensus" growth estimates as determined through surveys of stock research analysts. Differences between these published growth rates for any given company may be expected due to differences in the scope and timing of the surveys conducted. For purposes of selecting a five-year dividend growth rate, we relied on the Value Line DPS growth rate and earnings growth rates published by Value Line, Thomson, Zacks and SNL. In determining the selected five-year dividend growth rate, we used the average of the Value Line DPS growth rate and the nearest EPS growth rate as the estimate for dividend growth over the next five years. Because analyst estimates for EPS growth are often influential in estimating future dividend growth, we believe that the growth rates selected for each company are representative of investor expectations.

Q. How did you calculate the expected first year dividend (D_1) for each company?

A. Exhibit KCG-3 shows the current quarterly dividend for each company, the five-year DCF growth rate for each company, and the projected quarterly dividends over the next four quarters. Projected quarterly dividends were increased from current levels based on each company's historical timing for dividend changes. The size of each projected dividend change was based on the five-year DCF growth rate. The expected first year dividend (D_1) was then derived by adding the projected quarterly dividends over the next four quarters.

Q. How did you determine the expected long-term growth rates to be used in the DCF model?

A. We considered several factors that would have a significant influence on long-term investor expectations. In addition to considering the published growth rates for the comparable company group provided in Exhibit KCG-2, we also examined published growth rates for the electric utility industry and prospects for growth in the U.S. economy as a whole.

Q. What is a reasonable estimate of expected long-term growth for the electric distribution industry?

A. An annual growth rate of 6.5% percent represents a reasonable estimate of investor expectations for earnings and dividends over the long-run. As seen in Exhibit KCG-2, this growth rate is consistent with the median five-year EPS growth rate for the comparable company group, which ranges from 6.0% to 7.5% depending on which data source is relied upon. A growth rate of 6.5% also falls within a range that is bounded on the high side by investor expectations for the electric utility industry as a whole and is bounded on the low side by expectations for long-term growth in the U.S. economy. Five-year projected EPS growth rates for the electric utility industry as published by Reuters financial service and Zacks were 8.0% and 8.6%, respectively, in September 2006. Since these industry estimates include both vertically integrated utilities and distribution utilities, investor expectations for electric distribution utilities are probably slightly lower than these industry-wide projections. Additionally, since electricity distribution represents a basic utility service, it is reasonable to assume that this subset of the electric utility industry will grow at a rate closer to that of the overall U.S. economy over the long-run. Assuming annual economic growth of 6.0% over the long-run for the U.S. economy (see discussion below), it is reasonable to use a 6.5% long-term growth rate for the electric distribution industry.

Q. What is the long-term outlook for growth in the U.S. economy?

A. Projections of long-term economic growth can vary considerably depending on the assumptions made. However, real economic growth in the United States has been remarkably consistent over long periods of time, averaging 3.4% per year from 1929 through 2005. Since this growth has occurred over numerous business cycles, and during extended periods of war and peace, it is reasonable to use this historical growth in real gross domestic product ("GDP") as an estimate of future expected economic growth. In order to derive an estimate of nominal GDP growth, we added a long-term inflation rate of 2.6% to the estimated 3.4% growth in real GDP. The resulting growth in nominal GDP of 6.0% represents a reasonable expectation for future U.S. economic growth. The expected rate of inflation of 2.6% was calculated by subtracting the yield on 20-year inflation-indexed U.S. Treasury securities (2.27%) from the yield-to-maturity on 20-year fixed-rate U.S. Treasury bonds (4.84%) as of September 29, 2006.

Q. Did you use the expected industry growth rate as an estimate of long-term growth for the comparable companies?

A. Yes. We assumed that the long-term growth rate for each company would revert to the mean or expected long-term growth rate for the industry over time.

Q. How did you determine the current stock price for each comparable company?

A. A simple average of the daily closing prices was calculated for each company for the month of September 2006.

Q. What results did you obtain from the multi-stage DCF model?

A. Exhibit KCG-4 summarizes the results obtained, as well as each of the input variables used in the multi-stage DCF calculations. The estimated cost of equity for each company fell within a range of 9.7% to 10.5%. The median value for the sample group was 10.4%.

C. Application of CAPM.

Q. Please describe the capital asset pricing model.

A. The CAPM was developed using modern portfolio theory, which is premised on the assumption that capital markets are highly efficient and that investors attempt to optimize their risk/return profiles through diversification. Defining investment risk as the variability of expected future returns, the CAPM further assumes that risk is comprised of two components: systematic risk and unsystematic risk. Systematic risk is unavoidable, and is tied to macroeconomic factors that affect all companies. Unsystematic risk is company-specific, and theoretically can be eliminated through portfolio diversification. As such, the CAPM holds that investors should only be compensated for systematic risk. Mathematically, the CAPM is expressed as follows:

$$k_s = r_f + B_s \times (k_m - r_f)$$

Where: k_s = expected return on stock "s"
r_f = expected risk-free rate of return
B_s = beta for stock "s"
k_m = expected return on overall stock market

As a measure of systematic risk, the "beta" coefficient measures the extent to which returns on a given stock are correlated with returns on the overall market. Historical values for beta can be determined statistically by comparing total returns on a stock to the total returns on a market index. The risk-free rate of return "r_f" is typically estimated using the yield-to-maturity ("YTM") on U.S. Treasury securities. For common stocks, which have no defined maturity date, the YTM on long-dated Treasury bonds should be used as the risk-free rate. The difference between the expected market return and the risk-free rate, shown above as (k_m – r_f), is frequently referred to as the market risk premium. Estimates for the market risk premium are typically derived by examining historical rates of return for common stocks and U.S. Treasury securities over long periods of time. The time series data published by Ibbotson Associates is a commonly used reference for historical return and risk premium data. Using expected values for the market risk premium, beta, and the risk-free rate, the CAPM can be used to estimate the expected rate of return (or cost of equity) for any given stock.

Q. **How did you determine expected values for the market risk premium, beta, and the risk-free rate?**

A. Using the Ibbotson Associates time series data, we selected the historical market risk premium for the period 1926-2005 as a proxy for the expected market risk premium. This value, 7.1%, represents the arithmetic average of the excess returns of large company stocks over 20-year U.S. Treasury bonds. For the risk-free rate we selected the YTM on 20-year U.S. Treasury bonds as of September 29, 2006, or 4.8%. The beta for each company represents the published estimate from Value Line.

Q. **What results did you obtain from the CAPM?**

A. Exhibit KCG-5 summarizes the results obtained, as well as each of the input variables used in the CAPM calculations. With the exception of Cleco Corporation, which had an unusually high value for beta, the estimated cost of equity for each company fell within a range of 9.8% to 11.2%. The median value for the sample group was 10.5%, again excluding Cleco Corporation.

D. Cost of Equity for Comparable Companies.

Q. **What conclusions have you reached regarding the cost of equity for the comparable company group?**

A. The range of estimates obtained from the DCF model and the CAPM are summarized in the table below. Recognizing that each methodology has its own strengths and weaknesses, and recognizing that cost of equity analysis is not an exact science, we have selected a range of 9.7% to 11.2% as our estimate of the cost of equity for the comparable company group.

Summary of Comparable Company Analysis

	DCF Model	CAPM	Recommended Range
Low end of range	9.7%	9.8%	9.7%
High end of range	10.5%	11.2%	11.2%

VI. RETURN ON EQUITY FOR UNS ELECTRIC.

Q. How did you determine the cost of equity for UNS Electric?

A. This is best accomplished by comparing the risk profile of UNS Electric to that of the comparable company group. An appropriate range and point estimate for UNS Electric can then developed using the well established relationship between risk and expected return.

Q. How does the risk profile of UNS Electric differ from that of the comparable company group?

A. Relative to an investment in the group of comparable companies, an equity investment in UNS Electric is decidedly riskier. As I discussed earlier, UNS Electric received a speculative-grade credit rating of NAIC-3 when the Company issued long-term notes in 2003. Additionally, based on present and forecasted financial performance, as well as risks related to the Company's small size, high customer growth rate, the $60 million maturity of long-term debt in 2008 and the need to procure a new power supply by mid-2008, it is highly unlikely that UNS Electric would receive investment grade ratings today. By contrast, the median credit rating of the comparable company group is investment grade at Baa2 (Moody's) and BBB (Standard & Poor's). All of the comparable companies are also paying common dividends to shareholders, a situation not likely to occur anytime soon at UNS Electric. From the perspective of a common shareholder, an investment in UNS Electric is clearly riskier than an investment in the comparable company group.

Q. **Is it possible to quantify the additional cost of risk associated with an equity investment in UNS Electric?**

A. Yes. By examining the difference in required investor returns on investment grade and speculative-grade bonds, it is possible to quantify the equity risk premium applicable to UNS Electric. However, this observed difference in bond yields, or credit spread, can only be used to estimate the minimum equity risk premium. This is because an investment in common stock is much riskier than an investment in corporate bonds.

Q. **What is your estimate of the equity risk premium applicable to UNS Electric?**

A. I estimate that the minimum equity risk premium applicable to UNS Electric, relative to an investment in the comparable company group, is sixty basis points (or 0.6%). This estimate is based on the observed difference in bond yields for utility bonds with Triple-B credit ratings (Baa or BBB) and those having Double-B (Ba or BB) credit ratings. According to market data available through Reuters financial service, the average bond yield (or required investor return) for ten-year utility bonds was 79 basis points higher for Double-B bonds relative to Triple-B rated bonds as of September 29, 2006. This same data set revealed a credit spread of 63 basis points for bonds rated only one notch apart (high Double-B versus low Triple-B). Utility bond yield data published by Citigroup Global Markets indicate similar credit spreads for both seasoned and new issue utility bonds in 2006. Based on this information, I selected 60 basis points as the minimum equity risk premium applicable to UNS Electric.

Q. What is the estimated cost of equity capital for UNS Electric?

A. Adding the 0.6% equity risk premium to the cost of equity range determined for the comparable company group results in an estimated cost of equity of 10.3% to 11.8% for UNS Electric.

Q. What factors should be considered when selecting a point estimate for the cost of equity capital for UNS Electric?

A. As discussed above, UNS Electric faces the unique challenge of refinancing all of its long-term debt and replacing all of the Company's energy supply in 2008. UNS Electric is also very small relative to most investor-owned electric utilities, thereby limiting the Company's ability to withstand financial shocks arising from operating emergencies, reductions in customer demand, adverse regulatory decisions or other unforeseen events. The Company is also experiencing a much higher growth rate in net plant investment than any of the comparable companies. As a consequence, there is a continuing need for outside capital and a concurrent reduction in financial returns due to the Company's reliance on an historical test year for rate setting purposes. Moreover regulatory recognition of the challenges and increased risks UNS Electric is facing – as compared to other electric utility companies – is vital to the Company's ability to make the requisite equity investment. In light of these circumstances, I believe it is reasonable to use the high end of the range as a point estimate for the cost of equity capital for UNS Electric.

Q. Would you please elaborate on the growth that UNS Electric is experiencing, and how that growth affects the Company's ability to earn its authorized rate of return?

A. Yes. The following table summarizes the actual and forecasted growth in net plant investment, number of retail customers and investment per customer since the electric utility properties were acquired from Citizens in August 2003:

	Net Plant ($ Millions)	Customers	Investment per Customer
Aug. 2003	$92	80,000	$1,150
Dec. 2004	$103	85,464	$1,210
Dec. 2005	$127	89,103	$1,427
Dec. 2006 (Forecast)	$156	93,976	$1,655
Dec. 2007 (Forecast)	$185	98,210	$1,883
Dec. 2008 (Forecast)	$210	103,822	$2,023
% Growth 2003-2008:	128%	30%	76%

Although some of the growth in net plant investment is attributable to a high customer growth rate, much of it is due to the low embedded cost of plant acquired from Citizens, a higher cost of new construction and the need for continuing system improvements. As a result, UNS Electric's net plant investment is expected to increase by 76% on a per-customer basis over the five-year period ending December 2008. If additional generating facilities are acquired by UNS Electric between now and 2008, the Company's investment on a per-customer basis will be even higher. Due to the use of an historical test year for rate setting purposes, as well as the time required to process a rate application, the gap between embedded cost and incremental cost on a per customer basis makes it very difficult, if not impossible, for UNS Electric to earn its authorized rate of return.

Growth in net plant investment for the electric utility industry is forecasted by Value Line to be approximately 4.7% per year over the period 2005 – 2010. Likewise, the median growth rate forecasted by Value Line for the comparable company group is 4.6% per year. It is clear that UNS Electric is experiencing plant growth well above industry norms, a situation that increases the Company's need for new capital and timely rate recognition of new plant investments.

Q. What allowed ROE do you recommend for UNS Electric in this proceeding?

A. I recommend that the Commission adopt an allowed ROE of 11.8% in this proceeding. This allowed ROE is reasonable in light of the risks facing UNS Electric, the need for additional capital at UNS Electric, and the allowed returns recently granted to other electric utilities in the United States (see discussion below). Additionally, this level of return should also be sufficient, when coupled with other aspects of the Company's rate request, to support the financial integrity of UNS Electric and allow it to access capital on more reasonable terms.

Q. What allowed returns on equity have been authorized in other jurisdictions recently?

A. As seen in Exhibit KCG-6, over the past five years allowed ROEs for electric utilities have generally fallen within a range of 10% to 12%. When these allowed ROEs are compared to the prevailing yield-to-maturity on 20-year U.S. Treasury bonds at the time each rate case was decided, an implied equity risk premium can be calculated. Over the past two years these equity risk premiums have fallen within a range of 4.4% to 7.1% (see Exhibit KCG-7).

Q. If the observed relationship between allowed equity returns and long-term interest rates continues, what range of allowed ROEs would you expect in the current interest rate environment?

A. Exhibit KCG-8 shows the yield-to-maturity on 20-year and 90-day U.S. Treasury securities over the past two years as of September 29, 2006. As can be seen, short-term interest rates have steadily increased over this time period, whereas long-term interest rates have been relatively stable. Based on the 4.84% yield on U.S. Treasury bonds as of September 29, 2006, and the observed range of equity risk premiums described above (4.4% to 7.1%), it is reasonable to expect allowed returns on equity for electric utilities in the range of 9.2% to 11.9%. The recommended ROE of 11.8% for UNS Electric falls within this range.

VII. COST OF DEBT CAPITAL.

Q. What was UNS Electric's embedded cost of long-term debt for the test year?

A. As shown on Schedule D-2 of the Company's Application, the weighted average cost of long-term debt for UNS Electric was 8.16% as of the end of the test year. This cost reflects the interest rate of 7.61% on the long-term notes issued by UNS Electric in 2003, the amortization of related issuance costs, and 50% of the issuance cost amortization and commitment fees on the joint revolving credit facility established for UNS Electric and UNS Gas in 2005. Maintenance of this facility is critical for purposes of funding seasonal working capital needs and a significant portion of capital expenditures. As such, it is appropriate to reflect the annual fixed cost of this facility in the cost of debt for UNS Electric.

Q. What cost of long-term debt do you recommend in this case?

A. I recommend a cost of long-term debt of 8.22%. This rate was determined by adjusting the test year cost of debt for the cost of amending UNS Electric's credit facility, which occurred after the end of test year. This adjustment reflects the annual amortization of the amendment fees paid by UNS Electric, as well as the reduction in commitment fees realized by the Company as a result of the amendment. In addition to increasing the size and term of the credit facility (subject to Commission approval in Docket No. E-04204A-06-0493), the amendment also resulted in a fifty basis point (0.5%) decrease to the interest rate on credit facility borrowings. This interest rate reduction is reflected in the cost of short-term debt as discussed below.

Q. What cost of short-term debt do you recommend in this case?

A. I recommend use of the interest rate applicable to UNS Electric as of the end of September 2006. Under the terms of the amended credit facility, the Company may borrow at a rate of LIBOR (London InterBank Offering Rate) plus 1.0%. As of September 29, 2006, the rate for 3-month LIBOR was 5.36%. Adding the 1.0% short-term credit spread for UNS Electric results in a cost of short-term debt of 6.36%.

VIII. WEIGHTED AVERAGE COST OF CAPITAL.

Q. Please summarize your findings regarding the weighted average cost of capital for UNS Electric.

A. Based on the recommended capital structure, the proposed cost of debt, and UNS Electric's cost of equity capital, I recommend the Commission adopt an overall Rate of Return ("ROR") of 9.89%. This value, reflecting UNS Electric's weighted average cost of capital, is calculated as follows:

	% of Capital Structure	Component Cost	Weighted Average Cost
Common Equity	48.85%	11.80%	5.76%
Long-Term Debt	47.18%	8.22%	3.88%
Short-Term Debt	3.97%	6.36%	0.25%
Total	100.00%		9.89%

IX. FINANCIAL IMPACT OF RATE REQUEST.

Q. What is the financial impact of the Company's rate request?

A. Exhibit KCG-9 provides a summary of key financial indicators for the period 2004-2009 assuming the Company's rate request is granted in full and implemented in January 2008. As seen on page 1 of Exhibit KCG-9, the Company's earnings and cash flow are forecasted to improve if the requested level of rate relief is granted. As seen on page 4 of Exhibit KCG-9, two key credit quality metrics, FFO interest coverage and FFO as a percentage of total debt, are also forecasted to improve. However, as discussed previously, the Company is not forecasted to earn the recommended ROE of 11.8%. Additionally, as reflected on pages 2 and 3 of Exhibit KCG-9, UNS Electric will continue to depend on outside capital to fund projected plant growth. Substantial amounts of new debt and equity capital will be required in order to meet forecasted capital spending needs and to maintain a balanced capital structure at UNS Electric.

The forecast information presented in Exhibit KCG-9 is based on numerous base case assumptions regarding customer growth, use per customer, operating and capital expenditure levels, short-term interest rates and other factors that are subject to change over time. In addition, this forecast also assumes that the Company's proposed changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC") are approved, thereby eliminating any large over- or under-recovery of energy supply costs after the current full-requirements contract with Pinnacle West Capital Corporation ("PWCC") expires in 2008.

Q. Is the recommended ROE of 11.8% sufficient to support the financial integrity of UNS Electric?

A. Yes, so long as other key aspects of the Company's rate request are granted. Although the Company's financial forecast does not indicate that UNS Electric will actually be able to earn the 11.8% ROE recommended in this proceeding, the level of rate relief sought by the Company should enable it to access additional capital on more reasonable terms. Additionally, requested changes in the Company's PPFAC should provide UNS Electric with stability in its earnings and cash flow after the power supply contract with PWCC expires. Considered in its entirety, the Company's rate request appears to be sufficient to support the financial integrity of UNS Electric. However, if the requested level of cash rate relief is materially reduced, or if the PPFAC mechanism does not allow for timely recovery of power supply costs, then a higher ROE would be warranted.

X. RATE BASE TREATMENT OF CONSTRUCTION WORK-IN-PROGRESS.

Q. Is it necessary to include CWIP in rate base in order to support the financial integrity of UNS Electric?

A. Yes, it is. UNS Electric will continue to be dependent on outside capital for the foreseeable future in order to fund system growth and capital improvements. As reflected in the bottom chart on page 2 of Exhibit KCG-9, the Company's capitalization is projected to grow by 84% over the next four years, from $115 million at year-end 2005 to an estimated $212 million in 2009. This growth rate will be even higher if additional generating facilities are acquired by the Company, as discussed in the Direct Testimony of Michael J. DeConcini. UNS Electric will need to attract new outside lenders and additional equity capital in order to fund system growth and to refinance the Company's existing long-term notes. For UNS Electric to attract this capital on reasonable terms, the Company must have an opportunity to earn a reasonable rate of return on its capital and have a financial profile comparable to that of other firms in the industry.

As reflected in the Company's rate application, rate base treatment of the $10.8 million test year CWIP balance provides UNS Electric with approximately $2.1 million in additional annual revenues. Denial of this requested rate treatment would have a material adverse impact on the Company's rate relief and future earnings. The Company's ability to earn a reasonable return on its capital would be cast further into doubt, as the forecasted ROE for UNS Electric would drop by another 150 basis points (or 1.5%) in 2008 relative to the base case forecast summarized in Exhibit KCG-9. Likewise, key cash flow indicators would also be weaker than indicated in Exhibit KCG-9. As a result, I believe it would be difficult for the Company to attract new capital on reasonable terms. In light of the significant capital needs of UNS Electric, as well as the Company's need for credit when procuring new long-term energy supplies, a rate decision that supports the Company's creditworthiness and financial flexibility is critical at this point in time. Approving CWIP in rate base greatly helps the Company achieve those aims.

Q. Are there other valid reasons to include CWIP in rate base for UNS Electric?

A. Yes, there are. First, it should be recognized that this rate treatment represents one of the few tools available to help mitigate the effects of regulatory lag. Since UNS Electric is experiencing significant customer growth, and since the cost of new construction greatly exceeds the embedded cost of plant, the impact of regulatory lag on UNS Electric is more pronounced than on most utilities. Second, due to the relatively short timeframe required for most construction projects on the UNS Electric system, a large portion of the CWIP balance at June 30, 2006 has already been transferred to plant-in-service. Customers are already receiving a benefit from this investment, and the customer advances relating to these projects have already been recognized as a reduction to rate base. Third, by including CWIP in rate base in this proceeding, the time period between this rate case and the next rate filing by UNS Electric will hopefully be extended. Since the cost and time involved with rate case preparation are very significant for a small utility like UNS Electric, the extension of time between rate filings is beneficial to both the Company and its customers. UNS Electric still intends to file rate cases on a regular basis, but neither the Company nor its customers are served by forcing the Company to file another rate case shortly after this case concludes. Finally, the large negative acquisition adjustment to rate base agreed to by UNS Electric upon the acquisition of Citizens must be recognized. As a result of the purchase of the electric properties by UniSource Energy in 2003, current UNS Electric customers are benefiting from a significant discount to the original cost of the electric utility system.

Q. What do you recommend if the rate base treatment of CWIP is denied?

A. As noted earlier, the authorized rate of return should be increased. In addition, if CWIP is not allowed in rate base, the Commission should consider the rate base treatment of plant that was placed into service after the test year, otherwise known as Post-Test Year Plant. As of September 30, 2006, the amount of Post-Test Year Plant that was previously included in the test year CWIP balance was $6.7 million. This plant is already in service and is serving customers. Since the balance of Post-Test Year Plant is growing monthly, due to the ongoing completion of projects included in the test year CWIP balance, it would be appropriate to update this balance at a later date if Post-Test Year Plant is included in rate base.

Q. Has the Commission allowed the use of Post-Test Year Plant before?

A. Yes, Post-Test Year Plant was allowed in the following cases: *Rio Rico Utilities, Inc.*, Decision No. 67279 (October 5, 2004); *Arizona Water Co.*, Decision No. 66849 (March 19, 2004); and *Bella Vista Water Co., Inc.*, Decision No. 65350 (November 1, 2002).

Q. Please compare the use of CWIP and Post-Test Year Plant.

A. CWIP is a superior measure of the value of the Company's plant because it does not arbitrarily exclude the value of plant that is not yet in service. On a practical level, most electric utilities are constantly building new plant necessary to serve customers. In the case of UNS Electric, this factor is much more important because of the large amount of construction necessary to serve our customers. Additionally, due to the large difference between the embedded cost and incremental cost of plant, CWIP should be allowed for UNS Electric. If the Commission elects not to allow the inclusion of CWIP into rate base, Post-Test Year Plant should at least be allowed; this would help mitigate the harm to UNS Electric's future financial condition.

Q. Do you have any other recommendations relating to the inclusion of CWIP in rate base?

A. Yes, I do. If the Commission grants the Company's request to include CWIP in rate base, UNS Electric requests that it be allowed to continue accruing an allowance for funds used during construction ("AFUDC") on all eligible construction projects following this rate order. It is my understanding that accounting guidelines published by the Federal Energy Regulatory Commission ("FERC") require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals. While it would be reasonable to apply this guideline to long-term construction projects for which CWIP has been included in rate base, the majority of projects included in UNS Electric's test year CWIP balance were short-term in nature. Given that only a small amount of AFUDC has been accrued on the test year balance of CWIP, it would be unfair to require UNS Electric to cease accruing AFUDC on $10.8 million of CWIP on an ongoing basis, year after year. Additionally, application of this guideline would eliminate most of the earnings benefit associated with inclusion of CWIP in rate base, thereby aggravating the effects of regulatory lag on UNS Electric's earnings. For these reasons, UNS Electric requests that the Commission include language in the final order that authorizes the Company to continue accruing AFUDC on all eligible construction projects.

XI. FINANCIAL IMPACT OF DEPRECIATION POLICY.

Q. How does depreciation policy affect the financial condition of a regulated utility?

A. Depreciation is a non-cash expense included in the revenue requirement to provide a return of capital previously invested in long-lived assets. As a non-cash expense, depreciation is a source of internal cash flow that a utility can reinvest in new plant facilities. Higher annual depreciation rates will generate higher internal cash flows, thus improving a utility's credit profile and reducing a utility's dependence on outside capital over the short-run. However, since depreciation expense also reduces the balance of net plant included in rate base, over the long-run no financial advantage is gained by having higher annual depreciation rates. In general, it is best to design depreciation rates that properly reflect the useful economic lives of the assets placed into service.

Q. How do the depreciation rates recommended for UNS Electric compare with the rates previously approved for Citizens?

A. As discussed by UNS Electric witness Dr. Ronald E. White, the composite annual depreciation rate recommended for UNS Electric is 4.18%. This rate is significantly lower than the present 4.53% composite rate approved in the last general rate case for the Arizona Electric Division of Citizens. One of the key factors contributing to the reduction in depreciation rates is the over-depreciation of plant by Citizens prior to 2003.

Q. What is the financial impact of lower depreciation rates on UNS Electric?

A. The reduction in depreciation rates relative to prior periods contributes to a lower revenue requirement and reduced operating cash flows at UNS Electric. Over the short-run, this situation increases the Company's dependence on outside capital and lowers key cash flow ratios monitored by lenders. However, over the long-run, the Company's rate base and earnings will more properly reflect the useful life of the assets placed into service.

XII. INTEREST RATE ON DEFERRED FUEL AND PURCHASED POWER COSTS.

Q. What interest rate do you recommend be used to calculate carrying charges on the balance of deferred fuel and purchased power costs?

A. Costs deferred under the PPFAC mechanism proposed by Mr. Hutchens will likely be financed through UNS Electric's revolving credit facility. As discussed earlier, the interest rate on credit facility loans is equal to LIBOR plus 1.0%. For purposes of establishing a benchmark interest rate, I recommend using the rate published in the Wall Street Journal for three-month LIBOR and adding 1.0% to this rate. This interest rate would be updated monthly for purposes of calculating carrying charges on deferred balances, and would be applicable to both positive and negative balances of deferred costs.

XIII. SUMMARY OF SCHEDULES.

A. Schedules A-3 and A-4.

Q. Please describe the information contained in Schedules A-3 and A-4.

A. Schedule A-3 presents a summary of the capital structure, capital ratios and weighted cost of capital for the years ending December 31, 2004 and December 31, 2005, and the test year ending June 30, 2006. Schedule A-3 also presents similar information on a forecasted basis for the year ending June 30, 2007.

Schedule A-4 provides historical and projected information relating to construction expenditures, net plant in service and gross utility plant in service. The projected information for the period 2007-2009 is consistent with the base case financial forecast discussed earlier in my testimony. The values for net plant in service and gross utility plant are presented on a regulatory accounting basis, which differs slightly from the presentation used in the Company's audited financial statements and the financial forecast.

The version of Schedules A-3 and A-4 incorporating the proposed purchase of the Black Mountain Generating Station ("BMGS") reflects an additional $60 million capital outlay as described in the testimony of Mr. Kevin P. Larson. For illustrative purposes, the financing related to this proposed purchase is reflected in the projected year capitalization in Schedule A-3. An additional $60 million of capital expenditures has also been added in 2008 in Schedule A-4, with corresponding adjustments to net plant and gross plant in service.

B. <u>Schedules D-1 through D-4.</u>

Q. Please describe Schedule D in the Company's Application.

A. Schedule D consists of four parts, Schedules D-1 through D-4.

Schedule D-1 contains the Company's actual and proposed capital structure and weighted average cost of capital for the test year ended June 30, 2006. This schedule also contains projected information pertaining to the Company's capital structure and weighted average cost of capital as of June 30, 2007.

Schedule D-2 contains detailed information on UNS Electric's cost of long-term debt. Schedule D-2, page 1, provides a calculation of the weighted average cost of debt, both actual and proposed, for the test year ended June 30, 2006. Schedule D-2, page 2, contains a projection of the Company's cost of debt as of June 30, 2007.

Schedule D-3 indicates that UNS Electric had no preferred stock outstanding during the test year, and that there are no plans to issue preferred stock.

Schedule D-4 contains the Company's estimated cost of equity capital and the proposed ROE for use in this proceeding.

The version of Schedule D incorporating the proposed purchase of the BMGS includes projected financing associated with this purchase. For illustrative purposes this additional financing was added to the test year and projected year capitalization of UNS Electric. In developing these schedules it was assumed that the purchase would be financed with the same mix and cost of capital as recommended in this rate application.

C. <u>Schedules F-1 through F-4.</u>

Q. Please describe Schedule F in the Company's Application.

A. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement and a return on common equity calculation for the test year ended June 30, 2006. This same information is presented on a projected basis for the year ending June 30, 2007. The projected year information is presented using two different rate assumptions: (i) a continuation of present rates; and (ii) an assumed implementation of proposed rates as of July 1, 2006 (beginning of the projected year ending June 30, 2007).

Schedule F-2 contains a summary cash flow statement for the test year ended June 30, 2006. This same information is presented on a projected basis for the year ending June 30, 2007. The projected year information is presented using two different rate assumptions: (i) a continuation of present rates; and (ii) an assumed implementation of proposed rates as of July 1, 2006.

Schedule F-3 contains information on the Company's construction expenditures during the test year ended June 30, 2006. This same information is presented on a projected basis for calendar years 2007, 2008 and 2009.

Schedule F-4 contains a description of key forecast assumptions used in preparing the projected information appearing in Schedules F-1 through F-3

Q. Please comment on the projected information appearing in Schedules F-1 and F-2.

A. The financial projections that assume a continuation of current rates through June 2007 were taken from a base case financial forecast prepared for UNS Electric, the same base case forecast discussed earlier in my testimony. It should be noted that this forecast is based on numerous assumptions regarding sales growth, operating and capital expenditure levels, and other factors that are subject to change over time. Additional financial projections are provided in Schedules F-1 and F-2 that assume implementation of the Company's requested rates beginning July 2006. I would like to note that these additional projections are purely hypothetical and are included for the sole purpose of complying with the Commission's rate filing requirements. In Decision No. 66028 (July 3, 2003), the Commission ordered that UNS Electric's present rates remain in effect until August 1, 2007 unless emergency circumstances arise or other specific events occur. Thus, projections assuming that new rates are implemented in July 2006 have limited analytical value.

Q. Please describe the version of Schedule F that incorporates the proposed purchase of the BMGS.

A. For illustrative purposes the financial projections in Schedules F-1 and F-2 for the projected year ending June 20, 2007 were adjusted to reflect the proposed purchase of the BMGS. The projections relating to both "present rates" and "proposed rates" were adjusted to reflect an additional $60 million of capital expenditures, an additional $60 million of related financing, and higher annual expense levels for depreciation, property taxes and interest. The financial impact of the proposed rate reclassification, described in the testimony of Mr. Kevin P. Larson, was also incorporated in the "proposed rates" column by reducing projected purchased power and transmission expense. This adjustment was necessary to illustrate the financial impact of shifting approximately $10 million annually from UNS Electric's power supply revenues to the Company's base delivery charge revenues.

As noted at the bottom of Schedule F-3, this schedule was also adjusted to reflect an additional $60 million of capital expenditures in 2008 related to the proposed purchase of the BMGS.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

KCG-1

UNS Electric, Inc.
Comparable Company Data

	Electric Customers (12/31/2005)	Common Equity as % of Total Capital (6/30/2006)	Senior Unsecured Credit Rating		Market Capitalization ($ Millions) (6/30/2006)
			S&P	Moody's	
CH Energy Group, Inc. (1)	292,821	56.1%	A	A2	$ 757
Cleco Corporation	267,000	51.7%	BBB-	Baa3	$ 1,335
Hawaiian Electric Industries, Inc.	429,316	35.4%	BBB	Baa2	$ 2,269
MGE Energy, Inc (2)	136,000	54.7%	AA-	Aa3	$ 640
Northeast Utilities	1,878,045	34.5%	BBB-	Baa2	$ 3,179
NSTAR	1,145,550	33.8%	A	A2	$ 3,055
Puget Energy, Inc. (3)	1,018,082	44.1%	BBB-	Ba1	$ 2,497
UIL Holdings Corporation (4)	320,672	50.3%	-	Baa3	$ 832
Median Value	374,994	47.2%	BBB	Baa2	$ 1,802

Notes
(1) S&P Senior Unsecured Rating for Central Hudson Gas & Electric Corp is A. Moody's Senior Unsecured Rating for Central Hudson Gas & Electric Corp. is A2.
(2) S&P Senior Unsecured Rating for Madison Gas and Electric Company is AA-. Moody's Senior Unsecured Rating for Madison Gas and Electric Company is Aa3.
(3) S&P Long-Term Issuer Rating for Puget Energy, Inc. is BBB-. Moody's Long-Term Issuer Rating for Puget Energy, Inc. is Ba1.
(4) Moody's Long-Term Issuer Rating for UIL Holdings Corporation is Baa3.

Source: SNL Financial

EXHIBIT

KCG-2

Exhibit KCG-2

UNS Electric, Inc.
Projected Growth Rates for Earnings and Dividends
Comparable Company Group

		Projected Earnings Growth				
	Value Line Dividend Growth (2006-2010)	Value Line (2006-2010)	Thomson Financial (5-Year)	Zacks Investment Research (5-Year)	SNL Financial (5-Year)	5-Year Growth Rate for DCF
CH Energy Group, Inc.	0.5%	6.3%	NA	NA	NA	3.4%
Cleco Corporation	2.7%	7.7%	8.0%	8.0%	4.0%	3.3%
Hawaiian Electric Industries, Inc.	0.0%	3.9%	3.8%	5.3%	2.8%	1.4%
MGE Energy, Inc	1.1%	8.0%	NA	NA	NA	4.5%
Northeast Utilities	6.2%	6.9%	9.5%	8.7%	10.5%	6.6%
NSTAR	6.4%	6.4%	5.5%	5.8%	7.0%	6.4%
Puget Energy, Inc.	2.4%	5.7%	3.7%	7.0%	5.0%	3.1%
UIL Holdings Corporation	0.0%	2.2%	18.0%	18.0%	18.0%	1.1%
Median Values	1.7%	6.3%	6.8%	7.5%	6.0%	3.3%

EXHIBIT

KCG-3

Exhibit KCG-3

UNS Electric, Inc.
Calculation of Expected First-Year Dividend
Comparable Company Group

	Current Quarterly Dividend	Recent Dividend Change	Recent Ex-Dividend Date	5-Year Growth Rate for DCF	Expected Quarterly Dividends as of **9/30/06**				Expected First-Year Dividend
					4Q 2006	1Q 2007	2Q 2007	3Q 2007	
CH Energy Group, Inc.	$ 0.540	None	7/6/06	3.4%	$0.540	$0.540	$0.540	$0.540	$2.160
Cleco Corporation	$ 0.225	None	7/27/06	3.3%	$0.225	$0.225	$0.225	$0.225	$0.900
Hawaiian Electric Industries, Inc.	$ 0.310	None	8/11/06	1.4%	$0.310	$0.310	$0.310	$0.310	$1.240
MGE Energy, Inc	$ 0.348	3Q 2006	8/30/06	4.5%	$0.348	$0.348	$0.348	$0.364	$1.408
Northeast Utilities	$ 0.188	3Q 2006	8/30/06	6.6%	$0.188	$0.188	$0.188	$0.200	$0.764
NSTAR	$ 0.303	1Q 2006	7/6/06	6.4%	$0.303	$0.322	$0.322	$0.322	$1.268
Puget Energy, Inc.	$ 0.250	None	7/20/06	3.1%	$0.250	$0.250	$0.250	$0.250	$1.000
UIL Holdings Corporation	$ 0.432	None	9/1/06	1.1%	$0.432	$0.432	$0.432	$0.432	$1.728

EXHIBIT

KCG-4

Exhibit KCG-4

UNS Electric, Inc.
Multi-Stage DCF Analysis
Comparable Company Group

	Recent Average Share Price *	Projected Dividends					Long-Term Dividend Growth	Estimated Cost of Equity
		Year 1	Year 2	Year 3	Year 4	Year 5		
CH Energy Group, Inc.	$49.73	$2.16	$2.23	$2.31	$2.38	$2.46	6.5%	10.39%
Cleco Corporation	$25.14	$0.90	$0.93	$0.96	$0.99	$1.03	6.5%	9.70%
Hawaiian Electric Industries, Inc.	$27.10	$1.24	$1.26	$1.27	$1.29	$1.31	6.5%	10.33%
MGE Energy, Inc	$32.99	$1.41	$1.47	$1.54	$1.61	$1.68	6.5%	10.49%
Northeast Utilities	$23.09	$0.76	$0.81	$0.87	$0.92	$0.99	6.5%	9.81%
NSTAR	$32.82	$1.27	$1.35	$1.44	$1.53	$1.63	6.5%	10.35%
Puget Energy, Inc.	$22.44	$1.00	$1.03	$1.06	$1.09	$1.13	6.5%	10.45%
UIL Holdings Corporation	$37.13	$1.73	$1.75	$1.77	$1.79	$1.81	6.5%	10.35%
Median								10.35%

* Average share price for month of September 2006

EXHIBIT

KCG-5

Exhibit KCG-5

UNS Electric, Inc.
Application of Capital Asset Pricing Model
Comparable Company Group

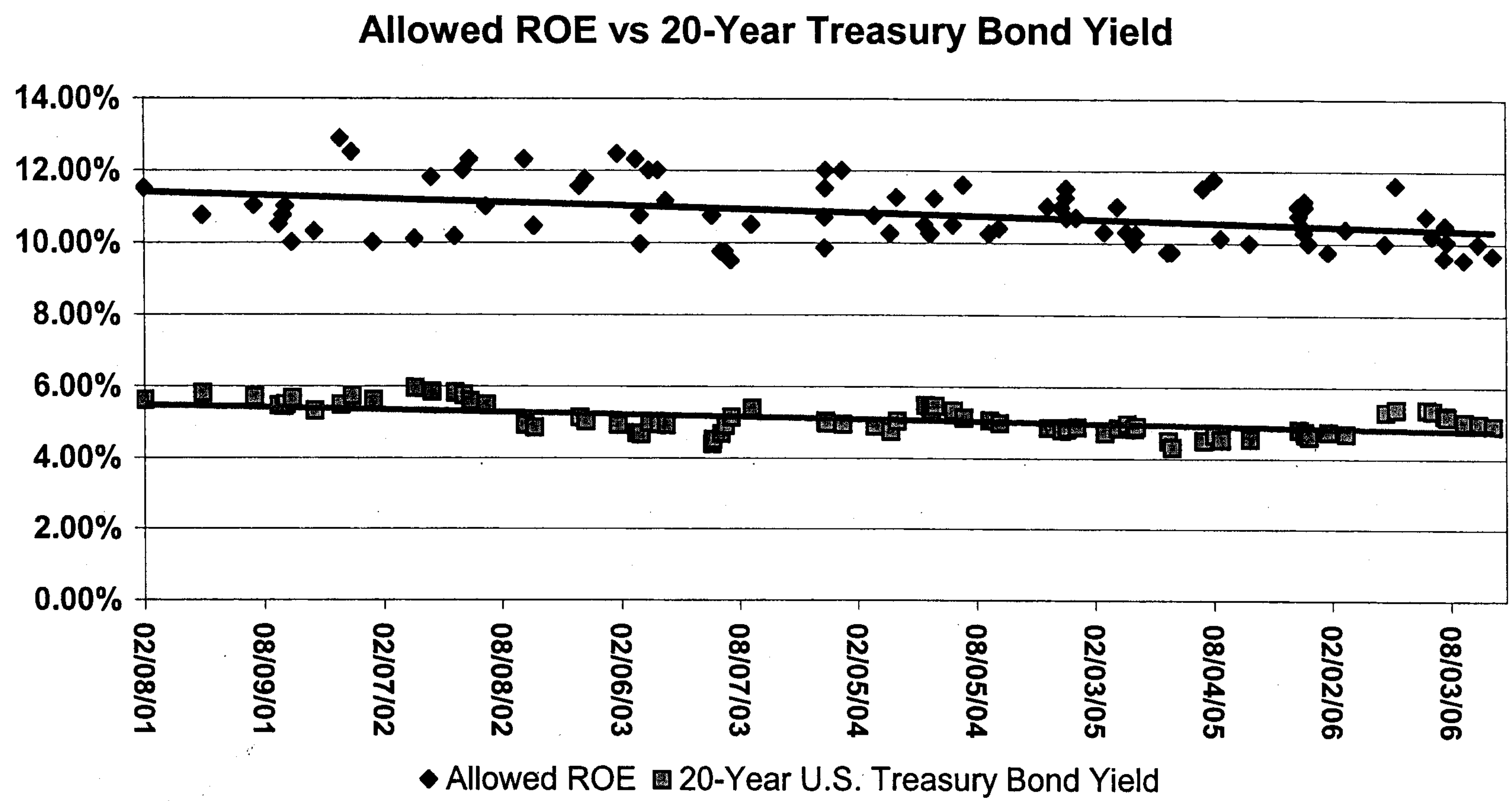
	Risk-Free Rate *		Beta**		Market Risk Premium		Estimated Cost of Equity
CH Energy Group, Inc.	4.84%	+	0.85	x	7.1%	=	10.9%
Cleco Corporation	4.84%	+	1.25	x	7.1%	=	13.7%
Hawaiian Electric Industries, Inc.	4.84%	+	0.70	x	7.1%	=	9.8%
MGE Energy, Inc	4.84%	+	0.70	x	7.1%	=	9.8%
Northeast Utilities	4.84%	+	0.85	x	7.1%	=	10.9%
NSTAR	4.84%	+	0.80	x	7.1%	=	10.5%
Puget Energy, Inc.	4.84%	+	0.80	x	7.1%	=	10.5%
UIL Holdings Corporation	4.84%	+	0.90	x	7.1%	=	11.2%
Median							10.7%
Median Excluding Cleco							10.5%

* Risk-free rate is the interest rate on 20-year treasury bonds as of 9/29/06
** Beta values are from Value Line

EXHIBIT

KCG-6

Exhibit KCG - 6



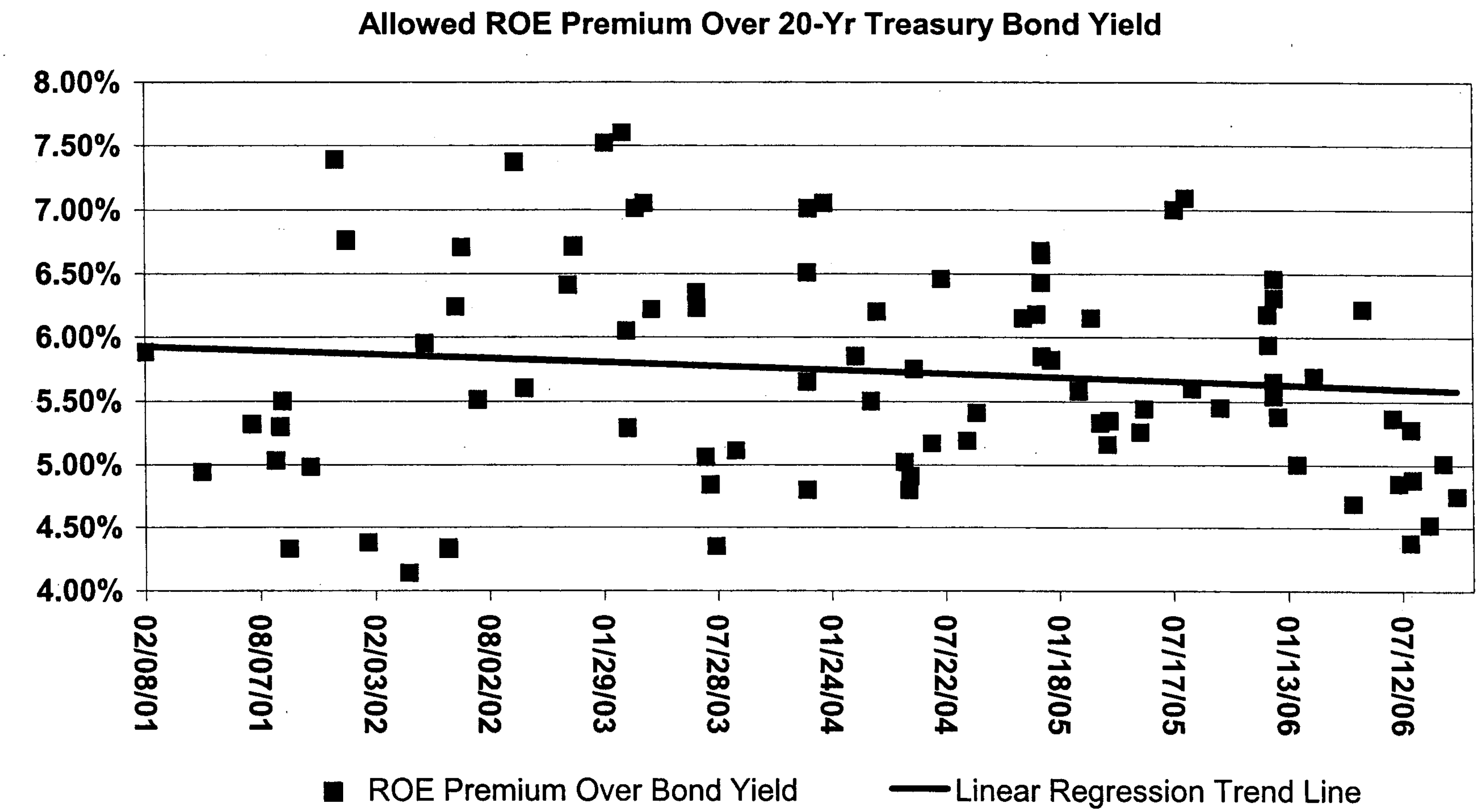
Note: Solid lines represent linear regression trend lines.

Source: 20-Year Treasury Bond Yields obtained from the Federal Reserve Board of Governors website (www.federalreserve.gov). Allowed ROE data obtained from Regulatory Research Associates.

EXHIBIT

KCG-7

Exhibit KCG - 7

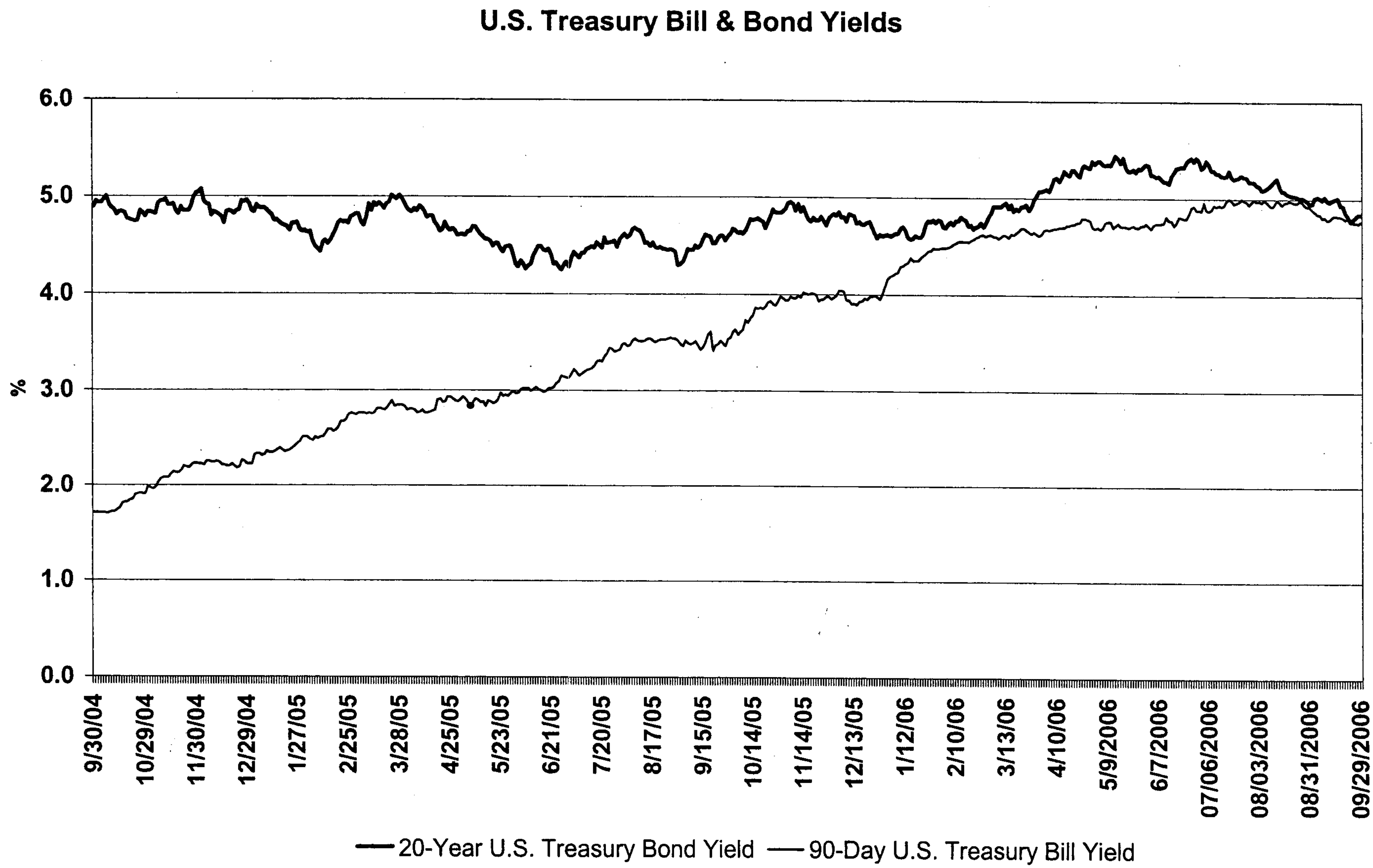


Note: Solid lines represent linear regression trend lines.
Source: 20-Year Treasury Bond Yields obtained from the Federal Reserve Board of Governors website (www.federalreserve.gov). Allowed ROE data obtained from Regulatory Research Associates.

EXHIBIT

KCG-8

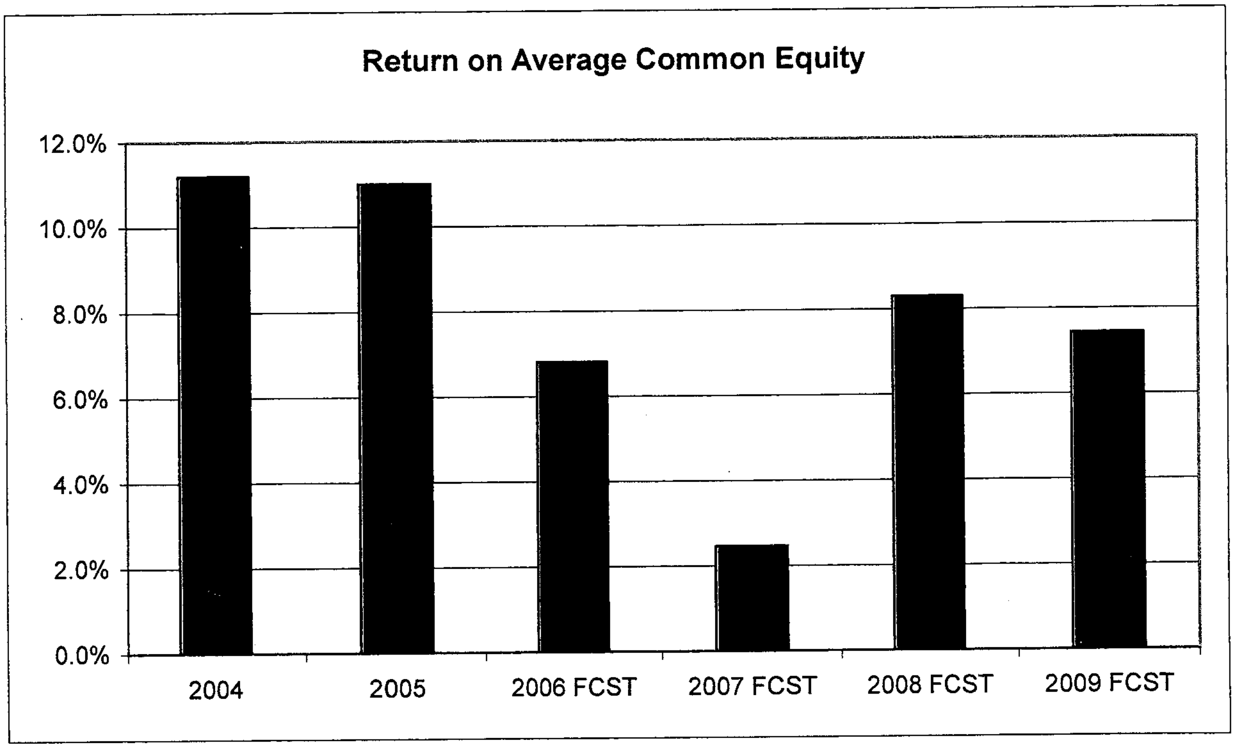
Exhibit KCG - 8

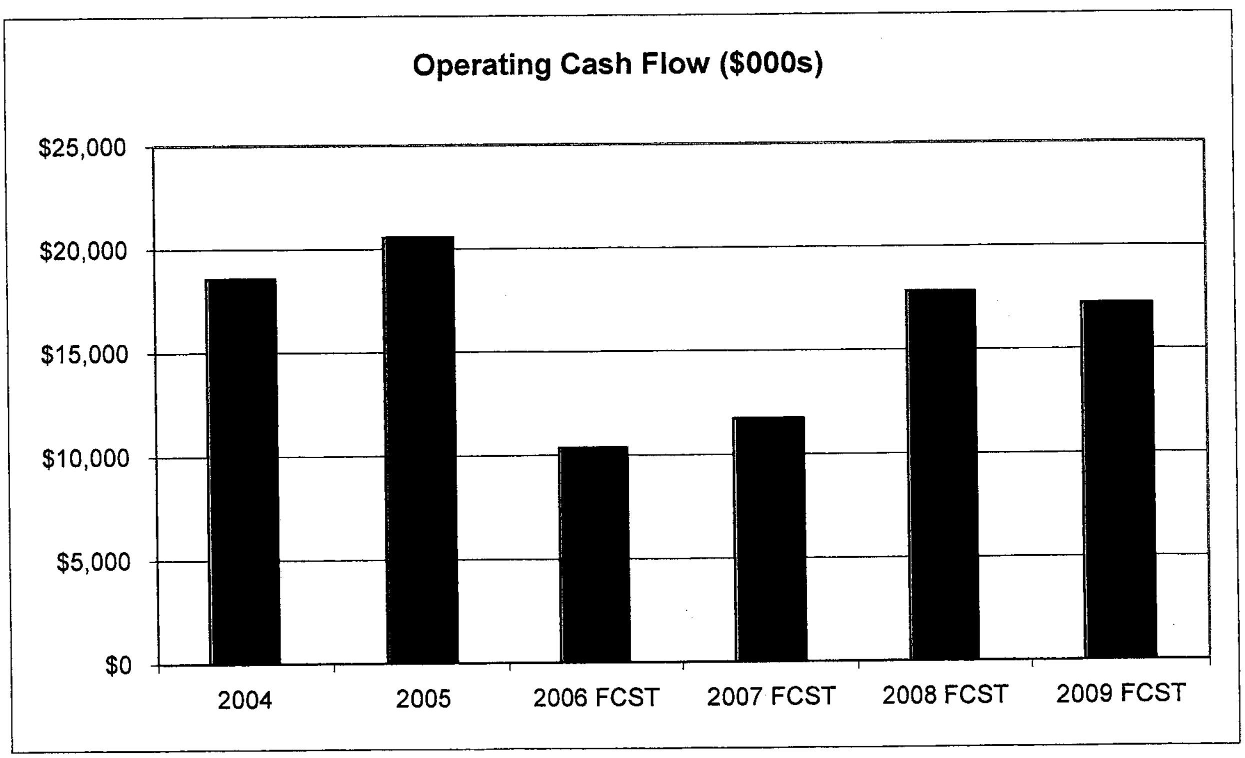


EXHIBIT

KCG-9

UNS Electric, Inc.
Base Case Financial Forecast
Summary of Key Financial Indicators





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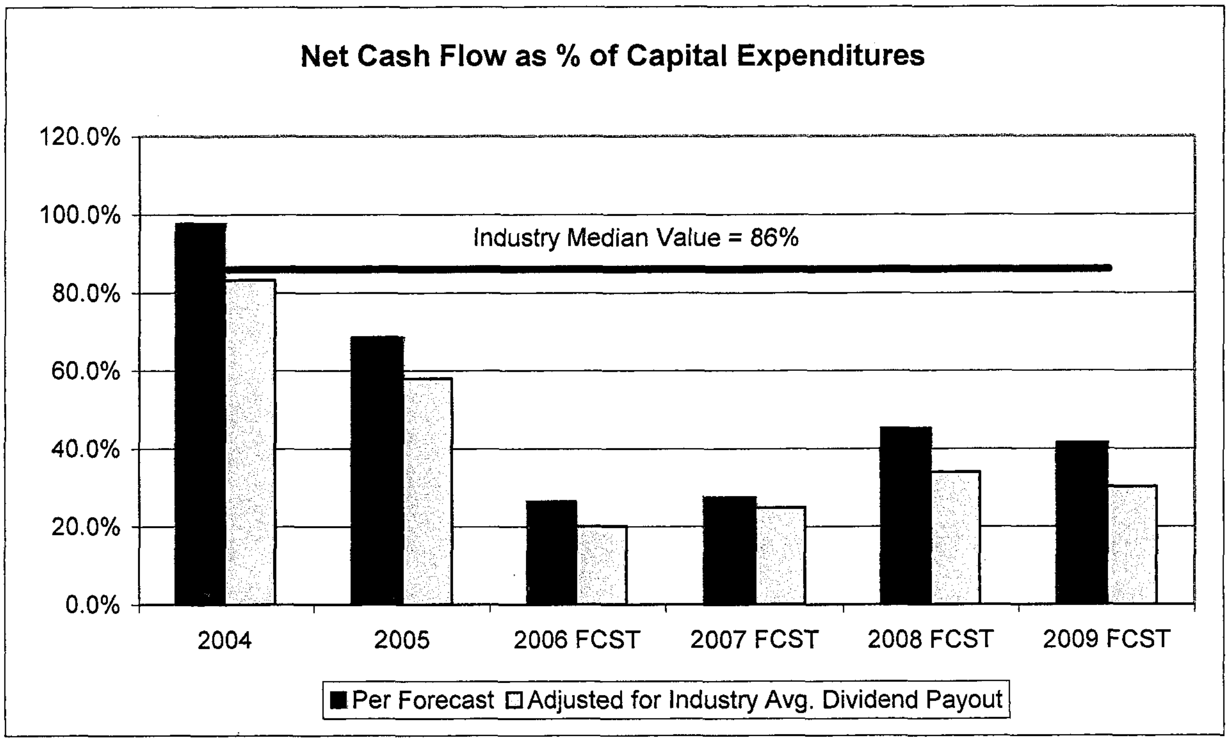
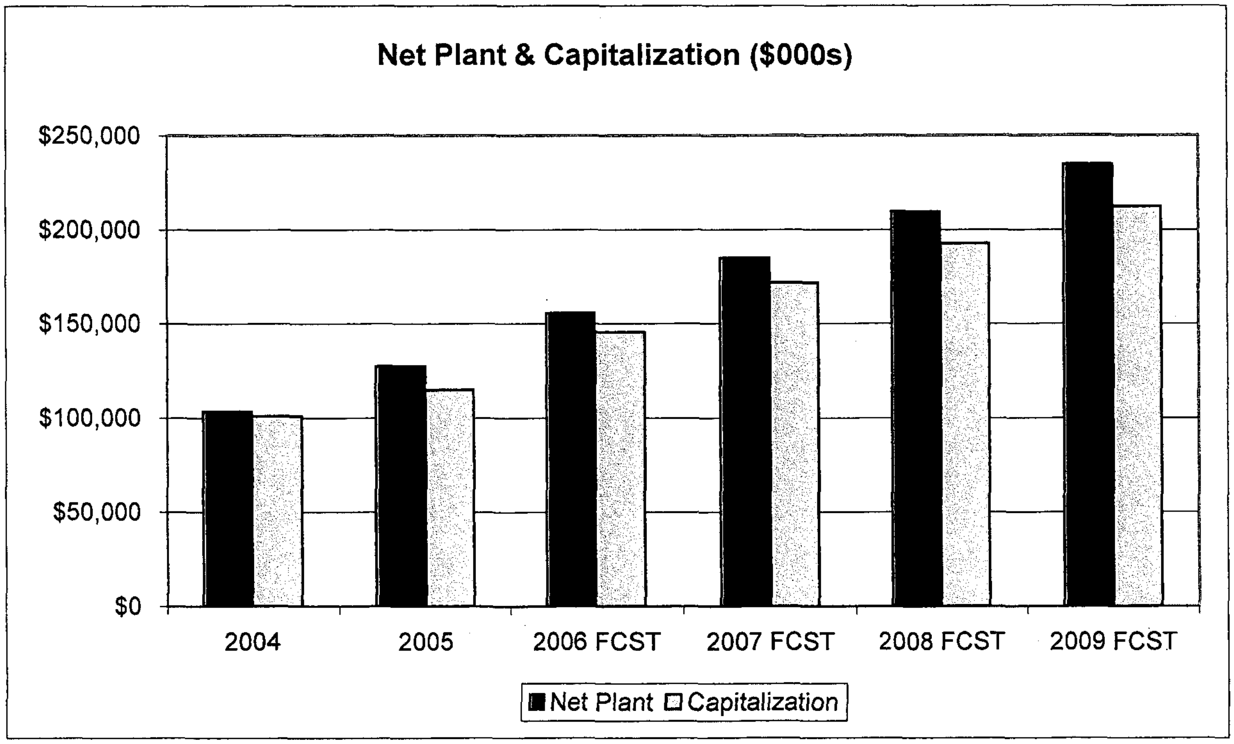
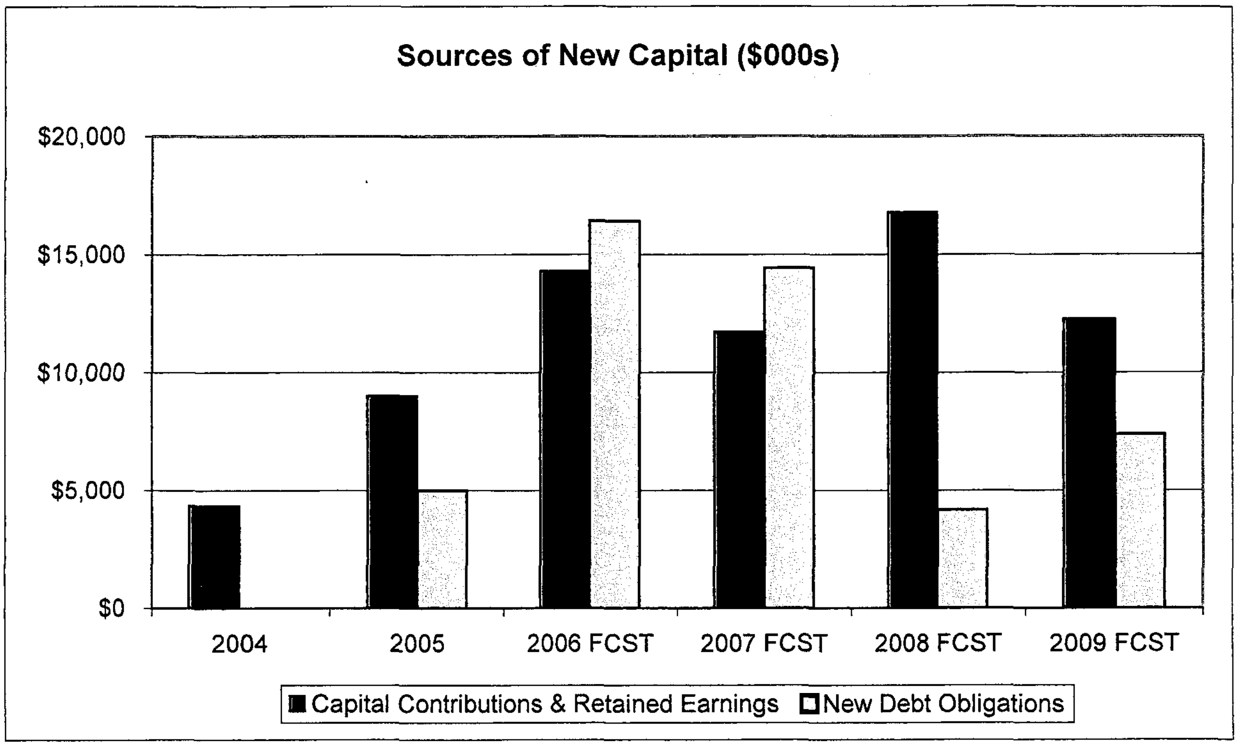
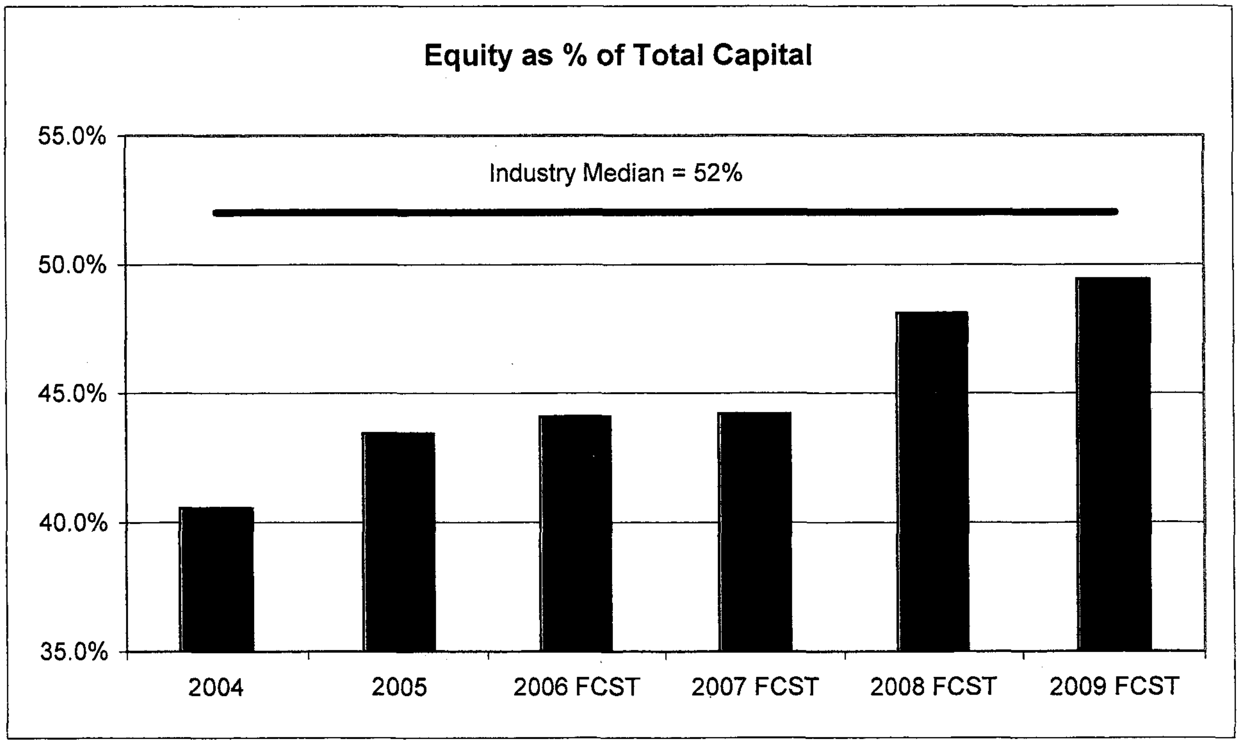
Base Case Financial Forecast
Summary of Key Financial Indicators





UNS Electric, Inc.
Base Case Financial Forecast
Summary of Key Financial Indicators





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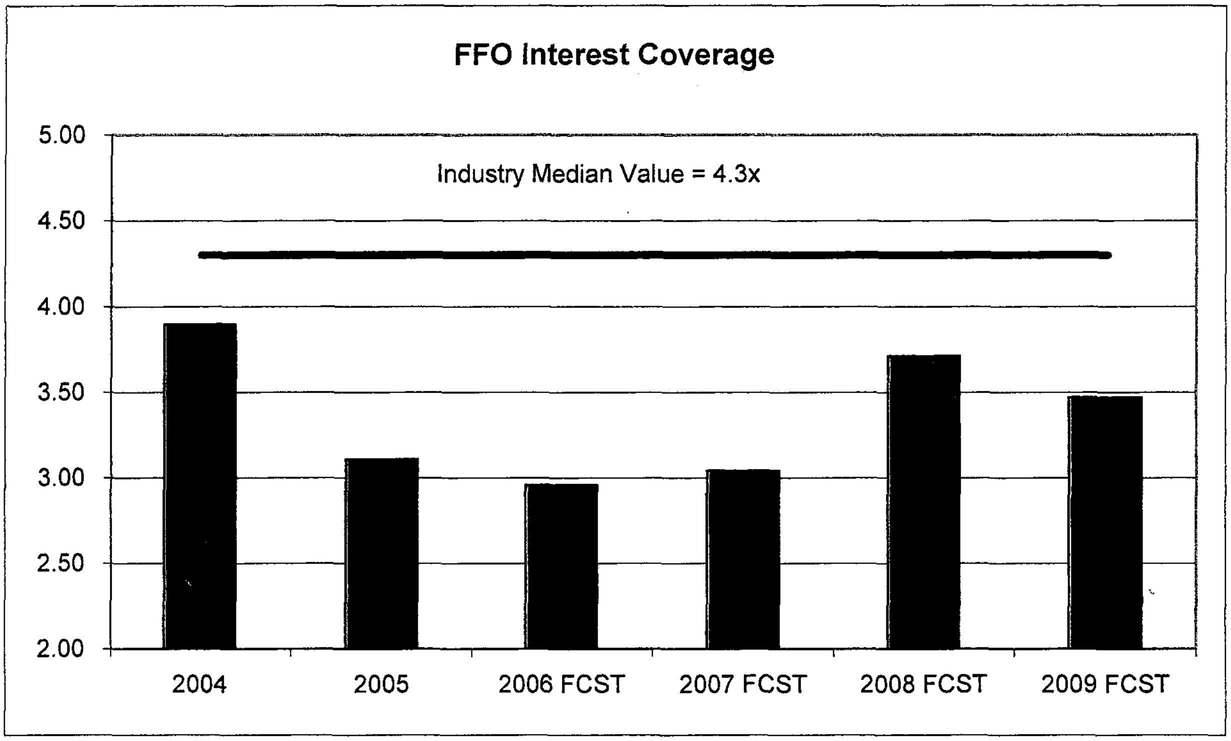
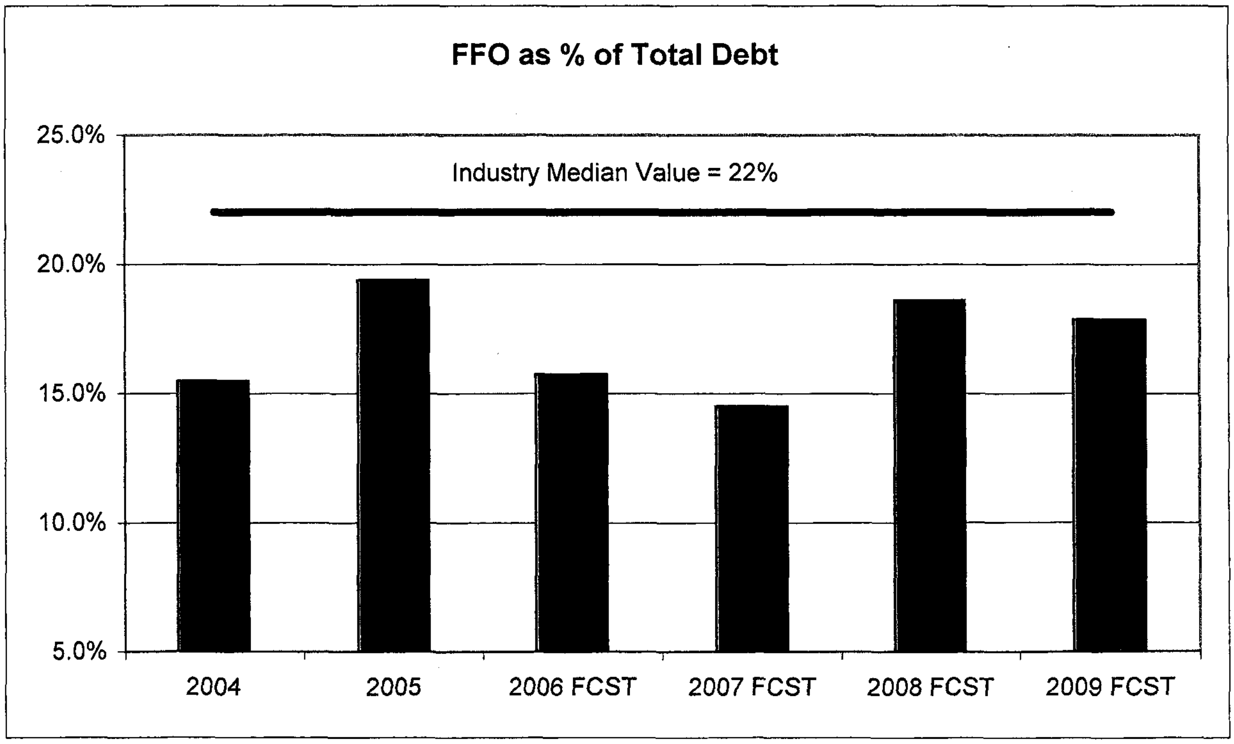
Summary of Key Financial Indicators





BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. G-04204A-06-783

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

August 14, 2007

EXHIBIT
tabbies
UNSE 35
Admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kentton C. Grant that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Please provide your general response to the Commission Staff and Intervenor testimony.

A. The rate increases recommended by the Commission Staff ("Staff") and by the Residential Utility Consumers Office ("RUCO") are clearly insufficient to support the financial integrity of UNS Electric, Inc. ("UNS Electric"). Neither party presented an analysis of how their recommendations would impact the Company's cash flow and earnings, two critical elements to consider when evaluating the ability of UNS Electric to attract capital on reasonable terms. Under Staff's proposed revenue requirement, the Company's earned return on equity ("ROE") is projected to be only four to five percent in the first full year that new rates are in effect. This ROE is substantially lower than the allowed ROE any Party is recommending in this case, and is even lower than the Company's cost of debt. Due to the impact of regulatory lag and the ratemaking adjustments proposed by Staff and RUCO, the end result of their recommendations is to deny UNS Electric any opportunity to earn a reasonable rate of return as required under the *Hope* and *Bluefield* court decisions. I note here that Staff and RUCO discuss both *Hope* and *Bluefield* in their respective Direct Testimonies; Mr. William A. Rigsby does so in his Direct Testimony at pages 6 through 7, while Mr. David Parcell does so in his Direct Testimony at pages 5 through 7.

The single largest factor contributing to the lower level of rate relief being recommended by Staff and RUCO is their rejection of the Company's request to include construction work-in-progress ("CWIP") in rate base. Unfortunately, this position appears to be based largely on philosophical grounds and does not take into account the financial realities facing UNS Electric and the facts I presented in my Direct Testimony. Likewise, the Company's alternative request to include a post-test-year adjustment to rate base was summarily dismissed by both parties. And since neither Staff nor RUCO adjusted the test-year balance of customer advances that are tied to the Company's CWIP balance, the positions taken by Staff and RUCO actually serve to penalize UNS Electric for having an ongoing construction program. At a minimum, the balance of customer advances related to the test year CWIP balance should have been removed by the Commission Staff and RUCO as additional rate base adjustments.

Finally, the allowed ROE and overall rate of return ("ROR") on invested capital recommended by Staff and RUCO are unreasonably low in light of the business risks faced by UNS Electric, the extraordinary impact of growth and regulatory lag on the Company's financial performance, and the need to raise additional capital for plant investment. The cost of capital witnesses for Staff and RUCO simply base their ROE recommendations on an analysis of large publicly-traded companies having a significantly lower risk profile relative to UNS Electric. Despite the fact that all of these companies currently pay common dividends and enjoy investment-grade credit ratings, attributes that UNS Electric does not share, neither witness acknowledged the additional risk and required rate of return associated with an equity investment in UNS Electric. Additionally, in quantifying the overall ROR to be applied to fair value rate base ("FVRB"), Staff has proposed a methodology that is mathematically equivalent to the "backing in" method that was expressly rejected in a recent Arizona Court of Appeals ruling involving Chaparral City Water Company ("Chaparral decision"). Staff's methodology should be rejected and replaced with a methodology that actually gives credence to FVRB in setting rates.

Q. Which Commission Staff and/or Intervenor testimony will you be addressing in your Rebuttal Testimony?

A. I will be addressing the testimony of the following witnesses:

- Mr. William A. Rigsby on behalf of RUCO (Cost of capital)
- Ms. Marylee Diaz Cortez on behalf of RUCO (CWIP in rate base)
- Mr. David C. Parcell on behalf of Staff (Cost of capital & CWIP in rate base)
- Mr. Ralph C. Smith on behalf of Staff (CWIP in rate base)

II. REBUTTAL TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. Mr. Grant, could you please summarize your view of Mr. Rigsby's Direct Testimony?

A. Yes. While Mr. Rigsby concurs with the Company's proposed capital structure and cost of debt, the allowed ROE of 9.3% recommended by Mr. Rigsby is unreasonably low. This recommended ROE is unreasonably low for three reasons. First, it is based in large part on a flawed discounted cash flow ("DCF") analysis for a sample group of publicly-traded electric utilities. Second, it does not reflect the substantial difference in risk between UNS Electric and his proxy group of electric utilities. And third, it is insufficient to support the financial integrity of UNS Electric, a concept that Mr. Rigsby acknowledges in discussing the *Hope* and *Bluefield* cases at page 6, lines 18 through 22, of his Direct Testimony.

Q. Please explain why you consider Mr. Rigsby's DCF analysis to be flawed.

A. Certainly. As can be seen on Schedule WAR-2 attached to his direct testimony, Mr. Rigsby uses dividend growth rates for his proxy group ranging from a low of 2.52% for UIL Holdings to a high of 6.01% for NSTAR. Since these growth rates are used by Mr. Rigsby in a single-stage constant growth DCF model, he implicitly assumes that these growth rates will remain in effect in perpetuity. From the standpoint of market expectations, there are two serious problems with this assumption.

First, compared to most industries, the electric utility industry remains highly regulated and is fairly homogeneous with respect to service offerings and type of capital investment. Although near-term expectations for dividend and earnings growth can vary widely between individual companies, over the long-run it is unrealistic to assume such a wide divergence in growth rates and shareholder returns. Over the long-run, investors are much more likely to expect a convergence of individual company growth rates toward the industry average growth rate. This approach to forecasting long-term growth rates, which assumes that growth rates for individual companies will revert to the industry average over time, is widely practiced by securities analysts and investors. Since Mr. Rigsby did not adjust his perpetual growth rates to account for this factor, the cost of equity estimates he obtained were unrealistically low for most of the companies he examined. Indeed, five of the companies in his proxy group have cost of equity estimates ranging from 6.60% to 7.81%, values that are just barely above comparable utility bond yields.

Second, when adjusted for inflation, the perpetual growth rates used by Mr. Rigsby assume a real rate of growth that is unrealistically low for most of the companies in his proxy group. Based on the difference between the yield on 20-year inflation indexed U.S. Treasury securities (2.7%) and the yield-to-maturity on 20-year fixed-rate U.S. Treasury bonds (5.3%), the expected long-term inflation rate for the U.S. economy was approximately 2.6% as of June 8, 2007. This is the terminal date Mr. Rigsby uses to calculate the average stock prices in his DCF analysis. Subtracting this expected inflation rate of 2.6% from the dividend growth rates that appear in his Schedule WAR-2 results in a range of expected *real* dividend growth rates of negative 0.1% to positive 3.4%. It is hard to fathom that investors would expect any company, even a highly regulated electric distribution company, to grow its earnings and dividends at a perpetual growth rate that is *less than* the expected rate of inflation. When adjusted for inflation, seven of the eight companies in his proxy group have a perpetual *real* growth rate of 1.7% or less. By contrast, expectations for long-term growth in the overall U.S. economy are likely closer to 3.4% in real terms. It is simply unrealistic to assume that dividends and earnings would grow at such a wide discount to overall economic growth for an industry providing basic utility infrastructure to an expanding U.S. economy.

Q. How did the results from Mr. Rigsby's DCF analysis affect his recommendation for an allowed ROE?

A. Mr. Rigsby derived his recommended ROE of 9.30% by averaging his DCF point estimate of 7.89% with the midpoint of 10.71% obtained from his application of the capital asset pricing model ("CAPM"). By giving equal weighting to his DCF and CAPM analyses, the end result of 9.30% is unreasonably low, is not supported by the range established in his own CAPM analysis, and is well below the midpoint of the range of 7.89% to 11.56% that Mr. Rigsby refers to as his "best estimate" of the cost of equity for UNS Electric (see page 30, lines 1 through 3 of Mr. Rigsby's Direct Testimony).

Q. If Mr. Rigsby's DCF analysis is disregarded, what cost of equity is obtained for his sample group of electric utilities?

A. The results obtained from his CAPM analysis, ranging from 9.85% to 11.56%, can be used as a more realistic estimate of the cost of equity for his sample group of utilities. Indeed, this range is very similar to the cost of equity estimate presented in my Direct Testimony for the same group of electric utilities (9.7% to 11.2%).

Q. In developing his final ROE recommendation, did Mr. Rigsby take into account the higher risk profile of UNS Electric relative to his sample group of electric utilities?

A. No, he did not. On page 55 of his Direct Testimony, Mr. Rigsby dismisses the company-specific risks faced by UNS Electric that I described in my Direct Testimony at pages 19 through 20. These distinguishing risk factors, each being of significant importance to an investor, are so large on a cumulative basis that they simply cannot be ignored. Relative to the companies in Mr. Rigsby's proxy group, UNS Electric is decidedly riskier for the following reasons:

- Speculative-grade credit rating,
- Lack of common dividend payment,
- Financial impact of growth and regulatory lag,
- Termination of all-requirements power supply contract in 2008,
- Maturity of all long-term debt in 2008, and
- Small size.

Even if Mr. Rigsby is correct in assuming that the Company's small size and power supply challenges should be given little or no weight, the other factors listed above represent risks that need to be clearly recognized in setting an allowed ROE for UNS Electric. At a bare minimum, even if the Company had an investment-grade credit rating, it is apparent that UNS Electric's cost of equity lies at the high end of the range established for the proxy group of companies analyzed by Mr. Rigsby. And when the speculative-grade credit rating of UNS Electric is taken into account – which adversely affects both the cost of debt and equity to the Company – it is also apparent that an equity risk premium must be added to the proxy group results. By ignoring the risk factors cited above, and failing to adjust the results of his proxy group analysis accordingly, Mr. Rigsby underestimates the Company's cost of equity by a very wide margin.

Q. Did Mr. Rigsby provide any analysis of whether or not his recommended ROR would be sufficient to permit UNS Electric to attract capital on reasonable terms?

A. No, he did not. Other than a blanket statement appearing in his Direct Testimony on page 6, lines 14 to18, Mr. Rigsby offers no analysis in support of his conclusion that his recommended ROR meets the criteria established in the *Hope* and *Bluefield* court rulings.

Q. Is Mr. Rigsby's recommended ROR sufficient to support the financial integrity of UNS Electric?

A. No, it is not. When coupled with RUCO's other recommendations, the rate relief recommended by RUCO is projected to result in an earned ROE of only 2.6% in the first full year after new rates are implemented. This ROE is clearly insufficient to attract additional equity capital and is detrimental to the Company's cash flow and credit profile as well. Mr. Rigsby, in his Direct Testimony on page 7 at lines 15 through 18, recognizes the need to provide UNS Electric with an opportunity to earn a reasonable ROR. But under his recommendation the only "opportunity" the Company would have to realize a reasonable ROR would be to lay off employees, slash other operating expenses and drastically reduce capital expenditures. Such moves would result in a very noticeable reduction to customer service, and would clearly not be in the public interest.

Q. How did you calculate the earned ROE that is projected to result from RUCO's rate recommendations?

A. RUCO is recommending a rate increase that is $7.2 million lower than the Company's request. Adjusting this figure for additional sales growth, this difference in annual revenues would grow to approximately $8.0 million by 2008. On an after-tax basis, this represents a decrease of approximately $4.8 million in net income relative to the Company's base case financial forecast for 2008, the results of which were summarized in Exhibit KCG-9 attached to my Direct Testimony. In that base case forecast, the Company projected net income of $7.0 million and a return on average common equity of 8.3%. As reflected in the following table, the Company's financial forecast would reflect a projected net income of only $2.2 million and a return on average common equity of 2.6% in 2008 when adjusted for the reduced level of rate relief recommended by RUCO.

($ millions)	Company Forecast (Exhibit KCG-9)	Adjustment	Forecast Adjusted for RUCO Proposal
Net Income	$7.0	($4.8)	$2.2
Return on Equity	8.3%	x (2.2 / 7.0)	2.6%

Q. Does that conclude your rebuttal to Mr. Rigsby's Direct Testimony?

A. Yes, it does.

III. <u>REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.</u>

Q. Mr. Grant, could you please summarize your view of Ms. Diaz Cortez's Direct Testimony?

A. Yes. Ms. Diaz Cortez rejects the Company's request to include CWIP in rate base on several grounds. After describing at length how the rate base treatment of CWIP is not an "accepted" ratemaking treatment – and why the Company must demonstrate that it meets an "extraordinary circumstance" standard – she goes on to state that this ratemaking treatment is not necessary to maintain the Company's financial integrity. Ms. Diaz Cortez also doubts the negative effects of regulatory lag and growth on UNS Electric's financial results, and refers to one of the Company's arguments on CWIP in rate base as being "disingenuous at best."

Q. Do you agree with Ms. Diaz Cortez' characterization of CWIP in rate base as not being an "accepted" ratemaking treatment?

A. No, I do not. The inclusion of CWIP in rate base as a means of supporting the financial integrity of public utilities has been an accepted form of ratemaking treatment for many years in many states. Although the standard for granting this ratemaking treatment varies by jurisdiction, I am not aware of any bright-line "extraordinary circumstance" standard that must be met in the State of Arizona to include CWIP in rate base. While both Staff and RUCO state that "extraordinary circumstances" must be met, neither Party provides *any* guidance as to what would meet their so-called standard. In essence, both RUCO and Staff are stating that under *no* circumstances should CWIP ever be allowed in rate base. While I recognize that rate base treatment of CWIP is not typical in the sense that it has not been used for many years in this jurisdiction, it is certainly a tool that is available to the Commission for purposes of setting fair and reasonable rates. And it is a tool other jurisdictions have employed for utilities in those jurisdictions.

Q. Are you aware of cases where CWIP was included in rate base in Arizona?

A. Certainly. Although I am not an attorney, I am aware of at least two Arizona Supreme Court cases decided in the 1970s that have discussed the issue of CWIP in rate base. For instance, it is my understanding that the Arizona Supreme Court did make the statement – in a rate case involving Arizona Public Service Company ("APS") – that the Commission could adopt any of a variety of approaches and consider plant under construction so long as the approach is not arbitrary. In a subsequent Arizona Supreme Court decision involving an APS rate case, my understanding is that the Court specifically stated that CWIP may be included in fair value rate base and that it was reasonable for the Commission to allow inclusion of CWIP in determining rates. I do not recall there being any language about how "extraordinary circumstances" were needed to put CWIP in rate base.

Q. What standard would you recommend using to determine whether or not CWIP should be allowed in rate base?

A. I recommend applying a financial integrity test. If the cash flow and earnings benefit associated with CWIP in rate base is needed to preserve the financial integrity of the utility, then it is clearly in the public interest to include CWIP in rate base. Financial integrity, or the ability to attract capital on reasonable terms, is a fundamental concept in utility regulation. As described in the *Hope* and *Bluefield* decisions, financial integrity is one of the fundamental goals of rate regulation.

The standard I propose is similar to that in other jurisdictions. For instance, the Florida Public Services Commission allowed $158,761,000 of CWIP in rate base for Tampa Electric Company in 1982 because "our overriding concern is to provide the utility with an opportunity to achieve and maintain adequate financial integrity" so that TEC could maintain its AA bond rating.[1] More recently, the Federal Energy Regulatory Commission ("FERC") has recognized that including a significant percentage of CWIP in rate base for Northeast Utilities Service Company[2] and Boston Edison Company[3] improves utilities cash flow in a less costly manner. Likewise, Virginia seems to have employed a standard that commonly allows CWIP in rate base.[4] In Texas, CWIP has been allowed in rate base on a number of occasions based on a consideration of the utility's financial integrity. In a case in which I testified as a staff witness on this subject, the Texas PUC allowed CWIP in rate base in order to support the financial integrity of Texas Utilities Electric Company.

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[1] 49 P.U.R. 547 (Fl.P.S.C. 1982).
[2] 114 FERC 61,089 (2006).
[3] 109 FERC 61,300 (2004).
[4] See In re Appalachian Power Company, 2007 WL 1616129 (2007).

Q. Even if the Commission were to require a finding of "extraordinary circumstance" in order to allow CWIP in rate base, would UNS Electric meet such a standard?

A. Yes, I believe it would. As I discussed on page 22 of my Direct Testimony, it will be very difficult, if not impossible, for the Company to earn its authorized rate of return over the next several years. This is due primarily to the high rate of customer growth in UNS Electric's service territory and the wide gap between the Company's embedded cost of plant and incremental cost of plant on a per-customer basis. Additionally, this growth is causing UNS Electric to raise large sums of additional capital to fund necessary plant investments. The combination of these factors, in my opinion, constitutes extraordinary circumstances that justify CWIP in rate base.

Other jurisdictions employing extraordinary circumstances standards have allowed CWIP in rate base when needed to protect a utility's financial integrity. For example, The New York Public Service Commission notes in its Generic Proceeding investigating financing plans for state gas and electric companies that when necessary to improve a utility's financial integrity and interest coverage levels, including CWIP in rate base is appropriate, along with other measures.[5] The Nevada Public Service Commission ("Nevada Commission"), in 1991, approved CWIP in rate base for 90% of two Nevada Power generation units – because to do so will ensure "a healthy utility to serve the ever growing needs of Southern Nevada."[6] UNS Electric's service area is also fast growing and it needs CWIP in rate base to best serve those areas.

More recently, on January 31, 2003, the South Carolina Public Service Commission ("SCPSC") allowed CWIP in rate base for South Carolina Electric and Gas Company.[7] The SCPSC explained that doing so "will improve the quality of the utility's earnings and

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[5] 49 P.U.R.4th 329 (N.Y.P.S.C. 1982).
[6] 132 P.U.R.4th 416 (1991).
[7] 225 P.U.R.4th 440 (2003).

send a constructive message to investors," and "will assist the Company in maintaining access to capital on reasonable terms during a period when the Company will be raising substantial capital in national markets." The SCPSC awarded a return on common equity equaling 12.45% in that case. On July 17, 2007, the Nevada Commission allowed $68,147,000 of CWIP for the "Harry Allen to Mead Transmission Line ("HAM Line")" for NPC, concluding that doing so "will lead to an improved financial situation for NPC, which can lead to lower borrowing costs to the benefit of [its] customers, thereby balancing the interests of ratepayers and NPC". The Nevada Commission found a return of equity for NPC between 10.25% and 10.97% to be reasonable.[8] Finally, the Maryland Public Service Commission allowed CWIP in rate base for Potomac Electric Power Company stating that doing so for certain construction projects reduces the need for construction-driven rate proceedings.[9] The Commission awarded a 10.00% return on equity.

Q. On page 16 of her Direct Testimony, Ms. Diaz Cortez characterizes the Company's financial integrity argument as being "without merit." Did Ms. Diaz Cortez offer any financial analysis to support this conclusion?

A. No, she did not. Although she makes reference to the financial integrity of "Arizona utilities" in general, and cites the positive effects of growth and regulatory lag on UNS Electric, she provides no analysis of the Company's financial performance on either an actual or forecasted basis, and provides no quantitative support for her statements regarding regulatory lag and growth.

[8] 2007 WL 2171450 (2007).
[9] 2007 WL 2159658 (2007).

Q. Do you believe it is necessary to include CWIP in rate base in order to preserve the financial integrity of UNS Electric?

A. Yes, I do. As I discussed in my Direct Testimony on pages 27 through 28, the ability of UNS Electric to earn a reasonable rate of return on its invested capital and to generate a healthy level of internal cash flow is essential if the Company is to maintain continued access to capital on reasonable terms.

Q. On pages 16 through 17 of her Direct Testimony, Ms. Diaz Cortez states that "…the Company's growth argument is without merit as growth has a positive effect on the Company, generating more revenue and cash flow." Do you agree with this statement?

A. No, I do not. While it is true that growth does generate additional revenue, and that over the long-run this growth will generate additional cash flow, Ms. Diaz Cortez ignores the fact that over the short-run the Company's earnings and cash flow are adversely affected by high customer growth. Meeting this growth requires substantial capital investment, currently at a level far exceeding the Company's internal cash flow. This additional investment creates additional fixed costs that UNS Electric must bear, including interest expense, depreciation expense and property taxes. Because of these additional costs, and the regulatory lag resulting from the use of an historical test year and a year-long rate review process, the Company's near-term earnings and cash flow are adversely affected by high customer growth.

Q. Can you provide an example showing the financial impact of customer growth and regulatory lag on UNS Electric?

A. Yes. In order to evaluate the financial impact of growth, we examined the growth in customers and net plant investment during the year ending June 30, 2007, the 12-month period immediately following the test year ending June 30, 2006.

Page 1 of Exhibit KCG-10 shows the increase in annual fixed costs associated with the $30million increase in net plant investment that occurred in the year ending June 30, 2007. Applying the Company's requested pre-tax ROR, the composite depreciation rate and the average property tax rate to this increased plant investment, the Company's annual fixed costs increased by approximately $6.0 million. As shown on page 2 of Exhibit KCG-10, new customers added during this same period resulted in an increase of approximately $1.2 million in annual delivery revenues. As summarized at the bottom of this same page, the difference between the $6.0 million of increased fixed costs and $1.2 million of increased delivery revenues represents an annual revenue *deficiency* of $4.8 million attributable to customer growth and plant investment. Stated another way, this $4.8-million deficiency represents the gap between the Company's required return on new plant investment and the Company's actual return on new plant investment. As a consequence, arguments to exclude CWIP from rate base on the basis of assumed growth-related benefits to UNS Electric simply do not hold water.

Q. Do you have any other comments regarding the example provided on Exhibit KCG-10?

A. Yes. Since additional operation and maintenance costs were not included in this example, this example likely understates the true impact on UNS Electric. Additionally, the plant investment balances used in the example already take into account the effects of depreciation and plant retirements. So the "benefits" of regulatory lag cited by Ms. Diaz Cortez – in her Direct Testimony on page 17 at lines 5 through 12 – have been fully reflected in the analysis. Finally, it should be noted that this quantification of financial impact relates to only a single year. UNS Electric has not had an increase in its delivery charges since the mid-1990s, well before UniSource Energy Corporation ("UniSource Energy") acquired the electric properties formerly held by Citizens in 2003. Additionally, the Company will not likely be able to implement new rates from this proceeding until early 2008, over a year and a half beyond the test year that ended June 30, 2006. Due to the passage of time, high customer growth and increasing plant investment on a per-customer basis, the cumulative annual revenue deficiency at UNS Electric is quite large. Since the rates currently charged by UNS Electric are based on costs for a test year ending March 31, 1995, there is an obvious need for adequate and timely rate relief at UNS Electric.

Q. Will the impact of growth and regulatory lag be as pronounced in future years?

A. Hopefully not. Although customer growth and plant investment are expected to remain high over the next several years, the gap between the Company's embedded plant investment and incremental plant investment on a per-customer basis should narrow over time. As may be seen in the table below, plant investment on a per-customer basis has increased by 47% over the past three years. Over the next three years, this measure of plant investment is expected to increase by a lower, yet still very high amount, of 26%. This table is similar to the one provided on page 22 of my Direct Testimony, but has been updated to reflect actual results for 2006 and has been expanded to include forecasted information for 2009.

	Net Plant ($ Millions)	Customers	Investment per Customer
Dec. 2003	$93	81,146	$1,147
Dec. 2004	$103	85,464	$1,210
Dec. 2005	$127	89,103	$1,427
Dec. 2006	$157	92,917	$1,690
Dec. 2007 (Forecast)	$183	98,210	$1,863
Dec. 2008 (Forecast)	$209	103,822	$2,013

Dec. 2009 (Forecast)	$234	110,314	$2,121
% Change 2003-2006	68.6%	14.5%	47.3%
% Change 2006-2009	49.0%	18.7%	25.5%

Q. How does this growth compare with the growth experienced by other major Arizona utilities?

A. It is substantially higher. As may be seen in Exhibit KCG-11, over the past three years (2003 through 2006) the growth in net plant investment on a per-customer basis was 3.1% for Southwest Gas Corporation, 14.3% for Arizona Public Service Company and 4.4% for Tucson Electric Power Company. Additionally, UNS Electric's rate of growth is even higher than that experienced by its sister company UNS Gas, Inc. ("UNS Gas"), which experienced growth of 19.1% in net plant investment on a per-customer basis over the past three years.

Q. Have the major credit rating agencies commented on the impact of growth and regulatory lag on regulated utilities?

A. Yes. All of the major credit rating agencies (Moody's, Standard & Poor's and Fitch) have commented on the need for timely cost recovery in rates and the impact of large capital spending requirements on regulated utilities. For example, in November 2006 Standard & Poor's published a report titled "Regulatory Rulings, M&A and Fuel Cost Recovery Dominate Global Utilities Credit Environment." In that report, Standard & Poor's makes a specific reference to the rate recognition of CWIP as a means of supporting utility credit ratings:

> "With few exceptions, regulatory outcomes have supported relatively strong credit characteristics for the utility industry. However, prospectively, regulators will be addressing large base-rate relief requests related to new generating capacity additions, environmental

> modifications on coal plants, and transmission and distribution (T&D) improvements. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes-significant cash flow drain, and reduces a utility's need to issue debt during construction. Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery."

Q. In her Direct Testimony on page 15, Ms. Diaz Cortez states that "...rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery." Do you agree with that statement?

A. If she is referring to a large multi-year construction project on which an allowance for funds used during construction ("AFUDC") is being accrued, then I would generally agree with her statement. However, in the case of UNS Electric, where the CWIP balance is comprised of many short-lived construction projects, I do not agree. As pointed out in my direct testimony, including the $10.8 million test-year balance of CWIP in rate base would provide the Company with an additional $2.1 million of pre-tax earnings and cash flow. This contribution to earnings far exceeds the $366,000 of AFUDC that UNS Electric recorded for all of 2005 and the $1.1 million of AFUDC recorded for all of 2006 (much of which was tied to the recently completed Valencia gas turbine). And since most of the $10.8 million test year balance of CWIP has already been transferred to plant in service, additional accruals of AFUDC on this test year balance will be quite small. In light of the earnings shortfall illustrated in Exhibit KCG-10, and the lack of significant AFUDC accruals on the test-year balance of CWIP, it is readily apparent that the inclusion of CWIP in rate base affects the level of earnings realized by UNS Electric. This rate treatment also provides an additional source of cash flow needed to fund capital expenditures, a benefit that non-cash accruals of AFUDC do not provide.

Q. On page 17 of her Direct Testimony, Ms. Diaz Cortez states that "The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit." Do you agree with that statement?

A. No. Although the timing of UNS Electric's next rate filing will depend on numerous factors, the earnings and cash flow benefit associated with CWIP in rate base should help to extend the period between this rate case and the next rate filing. As I pointed out in my Direct Testimony, rate case preparation is very costly and time consuming for a company the size of UNS Electric, and an extension of time between rate filings is beneficial to both the Company and its customers.

Q. On page 17 of her Direct Testimony, Ms. Diaz Cortez characterizes one of the Company's arguments on CWIP in rate base as being "disingenuous at best." What is your response to this characterization?

A. It is unfortunate that Ms. Diaz Cortez portrays the Company as being disingenuous. As shown on line 4 of Schedule B-1 in the Company's rate application, customers are receiving the full benefit of the $93 million negative acquisition adjustment just as promised in 2003, and will continue to receive that benefit until the negative acquisition adjustment is fully amortized. Additionally, customers will have also received the full benefit of a four-year rate moratorium, despite the obvious burden that the rate freeze has imposed on UNS Electric. What could not be reasonably foreseen in 2003, however, was the huge amount of capital required to meet customer growth and system improvement needs since that time. Similarly, it was difficult to predict the future impact of regulatory lag on UNS Electric. In short, the Company had no way of knowing in 2003 that it would need to request CWIP in rate base in 2006. Sadly, it appears that Ms. Diaz Cortez apparently views this as an attempt by the Company to take back part of the benefit associated with a large negative acquisition adjustment. By referring to the existence of a negative acquisition adjustment in this rate case, the Company is simply pointing out a fact that cannot be ignored when evaluating the need for timely and adequate rate relief.

Q. In excluding CWIP from rate base, Ms. Diaz Cortez made a $10.8 million downward adjustment to rate base. Did she make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Electric related to the $10.8 million CWIP balance was $1.9 million. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Ms. Diaz Cortez should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, RUCO is substituting "cost free" customer advances for $1.9 million of debt and equity capital supplied by the Company for plant in-service at the end of the test year. The end result of RUCO's rate base calculation is to penalize UNS Electric for having an ongoing construction program that is partially financed with customer advances.

Q. Did Ms. Diaz Cortez address the Company's alternative proposal for a post-test year adjustment to rate base?

A. No, I did not find any reference to that proposal in her Direct Testimony. It is likely that her views on post-test year plant adjustments are similar to the views she expressed on CWIP in rate base. However, it should be noted that as of June 30, 2007, $8.7 million of the test year balance of CWIP had already been closed to plant in service and was providing service to UNS Electric customers.

Q. Does that conclude your rebuttal to Ms. Diaz Cortez's Direct Testimony?

A. Yes, it does.

IV. REBUTTAL TO STAFF WITNESS DAVID C. PARCELL.

Q. Mr. Grant, could you summarize your view of the Direct Testimony filed by Mr. David Parcell on behalf of the Commission Staff?

A. Yes. The allowed ROE recommended by Mr. Parcell understates the cost of equity to UNS Electric by a substantial margin. This is due primarily to the conclusions he reached as a result of his CAPM analysis and comparable earnings approach, as well as to his dismissal of Company-specific risk factors and the speculative-grade credit rating assigned to UNS Electric.

The cost of debt and capital structure recommended by Mr. Parcell are very similar to those requested by the Company. However, because he did not take into account the cost of the amendment to UNS Electric's credit agreement completed in August 2006, his recommended cost of debt (8.16%) is slightly lower than the Company's current cost of debt (8.22%), and the percentage of long-term debt in Mr. Parcell's capital structure (47.21%) slightly exceeds the percentage used in the Company's proposed capital structure (47.18%).

For the reasons cited above, the overall ROR recommended by Mr. Parcell on the Company's original cost rate base ("OCRB") is unreasonably low. Additionally, due to his recommendation to assign a zero cost of capital to the difference between the Company's OCRB and FVRB, his recommended ROR on FVRB is also unreasonably low.

Finally, and most importantly, I find Mr. Parcell's analysis of UNS Electric's financial integrity to be severely lacking. The only quantitative financial analysis provided by Mr. Parcell on this topic is a hypothetical calculation of interest coverage that fails to consider the large reduction to the Company's requested rate relief being recommended by Staff.

Additionally, in rejecting the Company's request for CWIP in rate base, Mr. Parcell mistakenly assumes that UNS Electric receives its financing based on the credit quality of UniSource Energy and not on the "...situation of the Company itself." Since lenders and trade creditors having credit exposure to UNS Electric cannot look to UniSource Energy for repayment, the stand-alone credit quality of UNS Electric cannot be ignored, contrary to what Mr. Parcell suggests. By focusing attention on UniSource Energy and away from UNS Electric, it appears that Mr. Parcell is attempting to avoid the "end result" test that he describes on page 6 of his Direct Testimony, where he discusses the financial integrity test required under the *Hope* court ruling.

Q. Please elaborate on Mr. Parcell's cost of equity analysis.

A. Certainly. Regarding Mr. Parcell's DCF analysis, the range of 9.5% to 10.5% he established for his proxy groups is very similar to the range of 9.7% to 10.5% I observed for a similar group of companies. However, the range of 10.0% to 10.5% he established using the CAPM is significantly flawed in at least one respect. Due to this flaw, the cost of equity estimate made by Mr. Parcell in his proxy group analysis is significantly understated. Additionally, Mr. Parcell's comparable earnings analysis is based on a faulty underlying assumption and is influenced by reported earnings that are clearly outside of normal investor expectations.

Q. What issue do you have with Mr. Parcell's application of the CAPM?

A. In establishing a range for his CAPM analysis, Mr. Parcell uses a market risk premium that significantly understates the high end of that range. Although Mr. Parcell recognizes that investors consider arithmetic mean returns in forming opinions on the size of the market risk premium, he does not actually use the arithmetic mean risk premium in establishing his range of CAPM cost estimates. Instead, he uses the average of three different risk premiums in his CAPM calculations, two of which are substantially lower than the arithmetic mean risk premium. Doing so serves to understate the range of investor expectations for the market risk premium and the cost of equity. Had he used the 6.5% arithmetic mean risk premium he describes instead of the lower 5.9% "average" risk premium from page 25, lines 20 through 25 of his Direct Testimony, the upper end of the range for his CAPM results would have been higher by 0.5% using the median Beta values shown on Schedule 9 attached to his testimony. As a consequence, the upper end of the range for his CAPM analysis would have been 11.0% instead of the 10.5% value described in his testimony. By comparison, the upper end of the range established using the CAPM was 11.2% in my Direct Testimony, and 11.56% in Mr. Rigsby's Direct Testimony.

Q. Did Mr. Parcell also conduct a comparable earnings analysis?

A. Yes, he did. As reflected in the table on page 28 of his Direct Testimony, Mr. Parcell indicated that the average historical earned ROE for the proxy groups he examined ranged from 9.0% to 10.6%, while the average prospective ROE ranged from 9.5% to 10.7%. He uses these ranges to provide further support for his recommended ROE of 10.0% for UNS Electric.

Q. Should any weight be given to Mr. Parcell's comparable earnings analysis?

A. No. First, there is a false presumption that the historical earned returns reported by these companies and the accounting returns projected by Value Line are indicative of the cost of equity to these companies. Second, there are some obvious outliers in the data used by Mr. Parcell that cast further doubt on the validity of this approach.

Q. Please expand on your first concern.

A. Certainly. Several of the companies included in Mr. Parcell's comparison group, which are listed in the top half of Schedule 10 attached to his Direct Testimony, have significant investments in wholesale generation or non-utility affiliates. Furthermore, some of these companies have experienced prolonged periods of financial stress, including bankruptcy in the case of PG&E Corporation. Under these circumstances, it is difficult to understand how the historical earned returns reported by these companies can be used to estimate the forward-looking cost of equity for a regulated distribution company.

Q. Could you also expand on your second concern?

A. Yes. As may be seen on page 1 of Schedule 10 attached to his testimony, the data relied upon by Mr. Parcell includes some extreme outliers such as Northeast Utilities (3.8% historical earned ROE), PG&E Corporation (5.4% historical earned ROE) and DPL, Inc. (25.5% projected ROE). Such values are obviously not reflective of the cost of equity to a regulated utility, and serve to undermine Mr. Parcell's assumption that earned accounting returns for these companies are somehow indicative of the forward-looking cost of equity. If the presumption underlying the comparable earnings approach has any merit at all, then the earnings of a broader industry composite should be used instead of the relatively small sample groups used by Mr. Parcell. As may be seen in the first page of Attachment A to Mr. Rigsby's Direct Testimony, on the lower left hand corner, Value Line expects the composite return on common equity for the electric utility industry to be 11% for the periods 2007, 2008 and 2010-2012. On an historical basis, Value Line shows a composite earned ROE of 10.9% to 12.4% for the industry over the period 2003-2006. These values are significantly higher than the sample group averages cited by Mr. Parcell.

Q. Do you have any further comments regarding Mr. Parcell's cost of equity analysis?

A. Yes. Similar to Mr. Rigsby, Mr. Parcell dismisses the company-specific risk factors cited in my direct testimony for UNS Electric. As a consequence, his cost of equity estimate for UNS Electric is significantly understated. I discuss these company-specific risk factors, and why they must be considered in setting the allowed ROE for UNS Electric, when rebutting Mr. Rigsby's testimony earlier in my Rebuttal Testimony.

Q. On page 14 of his direct testimony, Mr. Parcell refers to a 2003 rating agency report on UNS Electric. Is UNS Electric rated by any of the major credit rating agencies?

A. No, it is not. However, as indicated in my Direct Testimony, the Company did receive a rating of NAIC-3 on the long-term debt issued to finance the acquisition of Citizens' Arizona Electric properties in August 2003. This rating was assigned by the credit committee of the Securities Valuation Office of the National Association of Insurance Commissioners ("NAIC").

Q. What does a security rating of NAIC-3 say about the credit profile of UNS Electric?

A. A rating of NAIC-3 is roughly equivalent to a speculative-grade credit rating of "BB" (or double-B) assigned by Standard & Poor's and Fitch, or the speculative-grade rating of "Ba" assigned by Moody's. By contrast, UNS Electric's sister company, UNS Gas, received a higher investment-grade rating of NAIC-2. The definitions for these security ratings, as published by the NAIC, are provided below (with emphasis added):

> **NAIC 2** is assigned to obligations of high quality. Credit risk is low but may increase in the intermediate future and ***the issuer's credit profile is reasonably stable.*** This means that for the present, the obligation's protective elements suggest a high likelihood that interest, principal or both will be paid in accordance with the contractual agreement, but there are suggestions that an adverse change in circumstances or economic, financial or business conditions will affect the degree of protection and lead to weakened capacity to pay. An NAIC 2 obligation should be eligible for relatively favorable treatment under the NAIC Financial Conditions Framework.

> **NAIC 3** is assigned to obligations of medium quality. Credit risk is intermediate and ***the issuer's credit profile has elements of instability. These obligations exhibit speculative elements.*** This means that the likelihood that interest, principals or both will be paid in accordance with the contractual agreement is reasonable for the present, but an exposure to an adverse change in circumstances or economic, financial or business conditions would create an uncertainty about the issuer's capacity to make timely payments. An NAIC 3 obligation should be eligible for less favorable treatment under the NAIC Financial Conditions Framework.

Q. Is there any reason to believe that UNS Electric would achieve a higher security rating today?

A. No. The Company is currently at a low point in terms of earnings and cash flow. While it is possible that UNS Electric could achieve a higher rating following the conclusion of this rate case, that possibility exists only if all (or substantially all) of the Company's requested rate relief is granted by the Commission.

Q. How does a speculative-grade credit rating affect the cost of debt and equity capital?

A. As I discussed on pages 20 through 21 of my Direct Testimony, a speculative grade credit rating adds at least 60 basis points (or 0.6%) to the cost of debt and equity. This observed risk premium is low relative to historical credit spreads, which were significantly higher just a few years ago. For example, in 2003 when UNS Electric and UNS Gas issued their existing long-term notes, investors required a coupon of 7.61% for UNS Electric and only 6.23% for UNS Gas. Furthermore, the maturity of the UNS Electric note was shortened to five years, compared with an average maturity of ten years for the UNS Gas notes. This real life example serves to illustrate the impact of credit quality on the cost of capital. Unfortunately, Mr. Parcell chooses to ignore this reality in making his cost of equity recommendation for UNS Electric.

Q. Did Mr. Parcell adopt the Company's proposed cost of debt and capital structure for UNS Electric?

A. Not exactly. While the Company adjusted the test year cost of debt and capital structure for the cost of amending UNS Electric's credit facility in August 2006, Mr. Parcell chose to use the unadjusted test year values. Since the Company was able to significantly reduce its cost of short-term borrowing by making this amendment, UNS Electric believes that it is appropriate to adjust the cost of debt and capital structure to reflect the cost of this amendment. Furthermore, the savings associated with this amendment are already reflected in the 6.36% cost of short-term debt proposed by the Company and used by Mr. Parcell in his overall ROR recommendation.

Q. On page 31 of his testimony, Mr. Parcell concludes that his cost of capital recommendation provides the Company with "a sufficient level of earnings to maintain its financial integrity." Do you agree with his conclusion?

A. No, I do not. Mr. Parcell made no attempt to determine whether or not the Company could actually earn his recommended ROE of 10.0% or his overall ROR of 8.99%. Based on all of the adjustments made by Staff, the recommended rate increase for UNS Electric is only $3.8 million, or 45% of the Company's requested increase. If Staff's recommendations were accepted in their entirety, the Company would have no opportunity to actually earn the ROR recommended by Mr. Parcell. As a result, the pre-tax interest coverage calculation presented on Schedule 14 attached to his Direct Testimony represents nothing more than a hypothetical example. While I appreciate Mr. Parcell's intent, which is to examine the impact of his recommendations on the Company financial integrity, it does not take into account the numerous adjustments made by other Staff witnesses that serve to limit any improvement in the Company's earnings and cash flow.

Q. Did Mr. Parcell make any other observations regarding the Company's financial integrity?

A. Yes. On pages 14 through 15 of his Direct Testimony Mr. Parcell addresses the Company's ability to attract capital. In this section of his testimony, he states that it is not "necessary" for UNS Electric to include CWIP in rate base in order to attract capital. In support of his conclusion, he cites rating agency reports that refer to UNS Electric as "low risk." However, the only rating agency report specifically cited by Mr. Parcell is a report by Standard & Poor's published in 2003. This report is now four years old and was written at a time when UNS Electric had five years remaining on a full-requirements power supply agreement and when the cumulative effects of growth and regulatory lag on UNS Electric had not yet materialized. Mr. Parcell also makes reference to the supposed ability of UNS Electric to attract financing based on the credit quality of UniSource Energy. However, this assumption is incorrect, since no guarantees of UNS Electric debt obligations have been issued by UniSource Energy, TEP, or any other corporate affiliate other than UniSource Energy Services ("UES"), the parent company of UNS Electric and UNS Gas.

Q. Do you agree with Mr. Parcell's conclusion that CWIP is not necessary for UNS Electric to attract capital?

A. I agree that over the short-run, assuming no significant changes occur in the capital markets, that UNS Electric could probably attract additional capital without having CWIP in rate base. However, what Mr. Parcell does not address is the ability of the Company to attract capital on *reasonable terms*. If capital market conditions were to deteriorate, resulting in tighter lending standards and a more risk averse environment, the Company would face significantly higher borrowing costs and a contracting market for its speculative-grade debt. Even if the capital markets were to remain fairly stable, the prospect of earning low single-digit returns on equity, having high capital spending requirements and no common dividend payout would cause any prospective equity investor to think twice before committing additional equity capital to UNS Electric. Under these circumstances, the Company would have to rely more heavily on debt capital to fund its capital spending needs. With this additional debt leverage comes additional lending risk, and the cost of debt to UNS Electric would likely increase significantly. Additionally, it should be recognized that the Company's borrowing capacity is not infinite. So while Mr. Parcell is correct that additional capital could probably be attracted over the short-run, the cost of this capital will be significantly higher, resulting in adverse long-term effects on the Company and its customers.

Q. Is the calculation of a hypothetical interest coverage ratio sufficient to determine whether or not UNS Electric will be able to attract capital on reasonable terms?

A. No, it is not. In order to assess the real financial impact of Staff's recommendations, it is necessary to examine the Company's financial forecast and to adjust that forecast for the reduced level of rate relief recommended by Staff. Financial forecasts for UNS Electric were provided to Staff through the discovery process, along with supporting calculations of key financial indicators. While I am well aware of the complexities involved in adjusting financial forecasts, it is a relatively easy task to assess the impact of a reduced rate recommendation on certain key financial measures such as net income, operating cash flow and return on equity.

Q. How does Staff's recommended rate increase impact key financial indicators forecasted for UNS Electric?

A. Staff has recommended a $4.7 million reduction to the Company's requested level of rate relief based on test-year sales levels. Adjusting this figure for additional sales growth, this difference in annual revenues would grow to approximately $5.2 million by 2008. On an after-tax basis, this represents a decrease of approximately $3.1 million in net income and operating cash flow relative to the Company's base case financial forecast for 2008, the results of which were summarized in Exhibit KCG-9 attached to my Direct Testimony. In that base case forecast, the Company projected net income of $7.0 million, a return on average common equity of 8.3%, and operating cash flow of $17.8 million in 2008. As reflected in the following table, the Company's financial forecast would reflect a projected net income of only $3.9 million, a return on average common equity of approximately 4.6%, and operating cash flow of $14.7 million in 2008 when adjusted for the reduced level of rate relief recommended by Staff.

($ millions)	Company Forecast (Exhibit KCG-9)	Adjustment	Forecast Adjusted for Staff Proposal
Net Income	$7.0	($3.1)	$3.9
Return on Equity	8.3%	x (3.9 / 7.0)	4.6%
Operating Cash Flow	$17.8	($3.1)	$14.7

If Mr. Parcell's hypothetical 10.0% earned ROE on Schedule 14 of his Direct Testimony is replaced with the 4.6% adjusted ROE from the table above, the pre-tax coverage ratio calculated by Mr. Parcell would fall from 3.0X to 1.9X. Although Schedule 14 attached to his testimony indicates that a minimum coverage ratio of 1.8X is required for a "BBB" investment-grade credit rating, such a rating would not be feasible for UNS Electric due to the cash flow impact of Staff's rate recommendation.

Q. Does UNS Electric have a more recent base case financial forecast that can be used to evaluate the prospective financial condition of the Company?

A. Yes. Exhibit KCG-12 provides an updated summary of projected key financial indicators. This exhibit has been updated to include actual reported results through June 30, 2007, and includes an updated base case forecast reflecting the Company's requested rate increase, as well as a forecast reflecting Staff's recommended rate increase. Additionally, it should be noted that the forecast reflecting Staff's proposal also incorporates the recommendation of Staff witness Bing Young to eliminate the free footage allowance for new line extensions, a recommendation that would reduce UNS Electric's net capital expenditures by approximately $3 million per year.

Q. What do these financial forecasts reveal about UNS Electric's need for rate relief?

A. Even under the base case, which assumes that UNS Electric's requested rate increase is granted in full, the Company will still not be able to earn its requested ROE. Due to the extraordinary growth in net plant investment, increases to operating expenses and the need for substantial amounts of new capital, the Company's earned ROE is projected to peak at 8.4% in 2008 (assuming a full year of rate relief) and is expected to decline gradually from that point forward. (See page 1 of Exhibit KCG-12.) Under the Staff case, the Company's earned ROE is projected to peak at 4.8% in 2008 (again assuming a full year of rate relief), and is expected to gradually decline in subsequent years. Based on this measure alone, it is apparent that the Company is in dire need of rate relief.

Q. How is the Company's credit profile affected by the rate increases proposed by UNS Electric and by Staff?

A. As may be seen at the bottom of page 1 of Exhibit KCG-12, under the Company's rate proposal operating cash flow is projected to improve modestly relative to the levels recorded in 2006 and forecasted for 2007. However, under the Staff case, operating cash flows are projected to remain near current depressed levels. This impact on cash flow can also be seen in two key credit quality ratios: the funds from operations ("FFO") interest coverage ratio and FFO as a percentage of total debt. These forecasted ratios, which are shown on page 3 of Exhibit KCG-12, indicate modest improvement relative to 2006 and 2007 under the Company's rate proposal. By contrast, Staff's rate proposal is projected to result in a further deterioration of these two key ratios. This trend is understandable since no significant improvement in operating cash flow is forecasted to occur per Staff's recommendations, while at the same time the Company is borrowing additional debt capital to fund capital expenditures. Such a scenario would not bode well for the Company's credit profile and access to capital.

Actual and forecasted values for two other credit quality ratios are shown on page 2 of Exhibit KCG-12. Net cash flow as a percentage of capital expenditures is expected to remain low relative to industry median values even if the Company is granted its full rate request. In terms of capital structure, UNS Electric's equity ratio is projected to improve gradually under the Company's rate proposal. Under the Staff case, however, the Company's equity ratio is projected to remain below the test year level of 49% through at least 2009 due to a combination of lower earnings and higher borrowing at UNS Electric. Furthermore, this forecast assumes that an additional $10 million of equity capital is injected into the Company in 2008. In light of the anemic ROE forecast for UNS Electric under Staff's rate proposal, it is unlikely that such an investment could be justified to UniSource Energy's shareholders.

Q. In light of these projections, do you believe that Staff's rate proposal would give UNS Electric an opportunity to earn a reasonable ROR and enable the Company to maintain its credit?

A. No, I do not. An earned ROE of four to five percent, coupled with further deterioration in the Company's debt and interest coverage ratios, will not allow the Company to maintain its credit or attract capital on reasonable terms.

Q. Would your opinion change if the Company were granted deferred accounting treatment for the Black Mountain Generating Station ("BMGS") as Staff's witness Ralph C. Smith recommends?

A. No, it would not. Such accounting treatment would do nothing for the Company's cash flow, even though large amounts of capital would have to be raised in order to fund the purchase of this $60 million to $65 million generating facility. Adding this additional capital, with no commensurate increase in cash flow, would seriously degrade the Company's credit profile.

Q. Has the Company prepared financial forecasts that include the proposed purchase of the BMGS?

A. Yes. Exhibit KCG-13 contains key financial ratio projections reflecting both the Company's rate proposal and Staff's rate proposal.

Q. What conclusions can be drawn from these forecasts?

A. First, as described in Mr. Kevin P. Larson's Direct Testimony, the Company's financial profile is modestly improved if the BMGS is afforded rate base treatment and the proposed rate reclassification is implemented upon commercial operation. As may be seen at the bottom of page 1 of Exhibit KCG-13, the most visible sign of improvement is the significant increase in operating cash flow under the Company's rate proposal. As may be seen on page 2 of this same exhibit, this also translates into a significant improvement in the ratio of net cash flow to capital expenditures in 2009. Although other key ratios under the Company's rate proposal remain about the same as shown in Exhibit KCG-12, which does not reflect the proposed purchase of the BMGS, the overall financial condition of UNS Electric is modestly improved despite having raised a substantial amount of additional debt and equity capital.

Under Staff's proposal, which reflects only a $3.8 million rate increase and a deferred accounting order for the BMGS, the forecasted results are decidedly different. Instead of increasing, the Company's operating cash flow is actually projected to decrease relative to current levels. And, since additional debt is needed to fund the purchase of the BMGS, the FFO interest coverage ratio and FFO as a percentage of total debt both decline markedly from current levels. (See page 3 of Exhibit KCG-13.) Additionally, despite the assumption that all non-fuel costs of the BMGS would be deferred on the Company's income statement, the earned ROE for UNS Electric is projected to remain in the four to five percent range through 2009. (See page 1 of Exhibit KCG-13.) Such a ROE is clearly insufficient to attract the capital needed to finance the proposed purchase of the BMGS.

Q. Does Mr. Parcell make a recommendation regarding the appropriate ROR to apply to fair value rate base ("FVRB")?

A. Yes, he does. On page 38 of his Direct Testimony, Mr. Parcell recommends assigning a zero cost of capital to the difference between OCRB and FVRB. This methodology is mathematically equivalent to the "backing-in" method traditionally used by Staff to determine the ROR on FVRB, a method that was recently found deficient by the Arizona Court of Appeals in the Chaparral decision.

Q. Do you have a different recommendation for determining the ROR on FVRB?

A. Yes, I do. I recommend that the Commission apply the weighted average cost of capital (or overall ROR) to the Company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than proposed by the Company, UNS Electric would still be limited to the original rate relief sought in the Company's rate application.

Q. Does that conclude your rebuttal to Mr. Parcell's Direct Testimony?

A. Yes, it does.

V. <u>REBUTTAL TO STAFF WITNESS RALPH C. SMITH.</u>

Q. Mr. Grant, could you please summarize your view of Mr. Smith's Direct Testimony?

A. Yes. Similar to Ms. Diaz Cortez, Mr. Smith rejects the Company's request for CWIP in rate base largely on philosophical grounds. Although he recognizes that the inclusion of CWIP in rate base is up to the Commission's discretion, he offers several reasons why Staff does not recommend this ratemaking treatment.

Q. What specific reasons are offered by Mr. Smith in rejecting the Company's request for CWIP in rate base?

A. On page 14 of his Direct Testimony, Mr. Smith offers four reasons for rejecting the Company's request for CWIP in rate base. The first two reasons, that CWIP in rate base is not normally allowed by the Commission, and that projects included in the test year CWIP balance were not yet in service as of the test year, are merely statements of the obvious; they are not reasons to automatically disallow CWIP in rate base for UNS Electric. The third reason, which relates to the need to recognize revenues produced by projects included in the test year CWIP balance, is both impractical and unnecessary. It is impractical due to the need to identify the incremental revenue generated by every customer added as a result of the test year investment in CWIP, which by definition includes numerous partially-completed projects that may facilitate customer additions over a number of years. It is also unnecessary for the reason explained in my rebuttal of Ms. Diaz Cortez; namely that growth is detrimental to UNS Electric's earnings over the short-run. The fourth and final reason offered by Mr. Smith in rejecting the Company's request is that UNS Electric has made no specific enforceable commitment to a rate case moratorium period. In offering this reason, Mr. Smith erroneously assumes that UNS Electric would somehow be in a position to make such a commitment prior to knowing how much rate relief it will receive.

Q. In excluding CWIP from rate base, Mr. Smith made a $10.8 million downward adjustment to rate base. Did he make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Electric related to the $10.8 million CWIP balance was $1.9 million. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Mr. Smith should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, the result is to penalize

UNS Electric for carrying a balance of CWIP at the end of the test year.

Q. Did Mr. Smith consider the Company's alternative request for including post-test year plant additions in rate base?

A. Yes, he did. However, he did not have any additional reasons to offer for rejecting this ratemaking alternative, which would provide rate base treatment for the $8.7 million of test-year CWIP that has already been place into service.

Q. Assuming the Company were allowed to put the test year balance of CWIP in rate base, does Mr. Smith agree with your recommendation to continue accruing AFUDC on all new construction projects?

A. No, he does not. Unfortunately, he believes that doing so would be improper and would "...give UNS Electric both a cash return on CWIP through its inclusion in rate base and an AFUDC return," as he notes in his Direct Testimony on page 17 at lines 8 through 10. He goes on to state that "If CWIP were to be allowed in rate base, which the Staff is not recommending in this case, then AFUDC accruals on the amount of CWIP included in rate base must cease." While UNS Electric agrees that it would be improper after new rates are implemented to continue accruing AFUDC on specific projects that (i) were included in the test year balance of CWIP and (ii) are still classified as CWIP at the time new rates are implemented, Mr. Smith is advocating something entirely different. Instead, Mr. Smith is advocating that the *amount* of test year CWIP allowed in rate base (e.g., $10.8 million per the Company's request) be deducted from all future CWIP balances in calculating AFUDC, even if the test year CWIP projects have long since been closed to plant in-service. As pointed out in my Direct Testimony, this would be unfair to a Company such as UNS Electric that has many short-lived construction projects in its CWIP balance at any given time. Since the FERC accounting guidelines on CWIP and AFUDC accounting were intended to address the inequity associated with earning both a cash return and an

AFUDC return on a large project at the same time, such as might occur with the construction of a large baseload generating facility, an exception to this accounting guideline is warranted in the case of UNS Electric.

Q. Do you have any other comments on Mr. Smith's testimony?

A. No. Most of his concerns regarding CWIP in rate base are similar to the concerns voiced by Ms. Diaz Cortez, which I have already addressed earlier in my Rebuttal Testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT

KCG-10

UNS Electric, Inc.
Impact of Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Fixed Costs from Plant Additions

Net Utility Plant at 6/30/07	$171,456,000
Less: Net Utility Plant at 6/30/06 (end of test year)	($141,550,000)
Increase in Net Plant for Year Ended 6/30/07	$29,906,000
x Fixed Cost Factor	20.05%
Increase in Annual Fixed Costs	**$5,997,054**

Derivation of Fixed Cost Factor:

	% Capital Structure	Cost	Weighted Cost	Tax Factor	Pre-Tax Cost
Equity Capital	48.85%	11.80%	5.76%	1.635	9.42%
Long-Term Debt Capital	47.18%	8.22%	3.88%	1.000	3.88%
Short-Term Debt Capital	3.97%	6.36%	0.25%	1.000	0.25%
	100.00%		9.64%		13.55%

Composite Depreciation Rate	4.18%
Composite Property Tax Rate	2.32%
Annual Fixed Cost of Plant Additions	20.05%

UNS Electric, Inc.
Impact of Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Delivery Revenues from Customer Additions

	Residential	Commercial	Other	Industrial	Total
Estim. Increase in Customers for Year Ended 6/30/07	2,483	219	9	0	2,712
x Use per Customer (normalized test year kWh)	10,355	63,135	1,308	N/A	14,588
Increase in Annual kWh Sales	25,714,313	13,831,180	12,211	-	39,557,704
x Average Revenues per kWh (test year)	$0.0303	$0.0287	$0.1110	N/A	$0.0298
Increase in Annual Revenues	$779,544	$397,633	$1,356	-	**$1,178,533**

Increase to Annual Revenue Deficiency from Plant and Customer Additions

Increase in Fixed Costs	$5,997,054
Less: Increase in Delivery Revenues	($1,178,533)
Increase to Revenue Deficiency	**$4,818,521**

EXHIBIT

KCG-11

Growth Rates Experienced by Arizona Utilities

Southwest Gas Corporation

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$1,138	985,043	$1,155
1996	$1,278	1,044,506	$1,224
1997	$1,360	1,104,060	$1,232
1998	$1,459	1,162,831	$1,255
1999	$1,581	1,224,770	$1,291
2000	$1,686	1,289,104	$1,308
2001	$1,826	1,348,970	$1,354
2002	$2,034	1,407,286	$1,445
2003	$2,176	1,467,752	$1,483
2004	$2,336	1,550,509	$1,507
2005	$2,489	1,645,004	$1,513
2006	$2,668	1,745,125	$1,529
Compound Annual Growth Rate (1995 - 2006)	8.1%	5.3%	2.6%
Absolute Growth Over Last 3 Years (2003 - 2006)	22.6%	18.9%	3.1%

Arizona Public Service Company

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$4,647	704,993	$6,592
1996	$4,655	737,504	$6,312
1997	$4,678	766,531	$6,103
1998	$4,731	796,410	$5,940
1999	$4,753	826,935	$5,748
2000	$4,910	864,990	$5,676
2001	$5,059	892,805	$5,666
2002	$5,886	921,251	$6,389
2003	$6,070	953,251	$6,368
2004	$6,258	989,502	$6,324
2005	$7,525	1,033,423	$7,282
2006	$7,827	1,075,191	$7,280
Compound Annual Growth Rate (1995 - 2006)	4.9%	3.9%	0.9%
Absolute Growth Over Last 3 Years (2003 - 2006)	28.9%	12.8%	14.3%

Growth Rates Experienced by Arizona Utilities

Tucson Electric Power Company

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$1,125	302,517	$3,719
1996	$1,117	310,950	$3,592
1997	$1,116	316,895	$3,522
1998	$1,114	324,866	$3,429
1999	$1,293	334,137	$3,869
2000	$1,298	342,914	$3,786
2001	$1,299	350,938	$3,701
2002	$1,480	359,372	$4,118
2003	$1,506	367,239	$4,101
2004	$1,538	375,532	$4,096
2005	$1,616	384,898	$4,199
2006	$1,681	392,477	$4,283
Compound Annual Growth Rate (1995 - 2006)	3.7%	2.4%	1.3%
Absolute Growth Over Last 3 Years (2003 - 2006)	11.6%	6.9%	4.4%

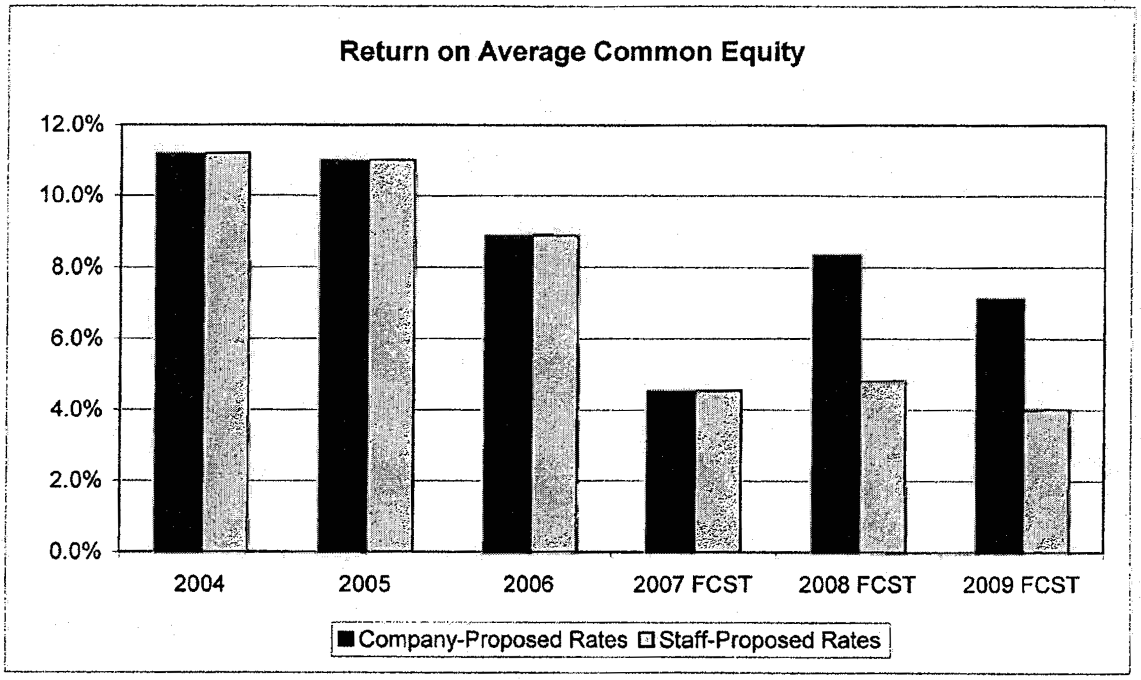
UNS Electric, Inc.

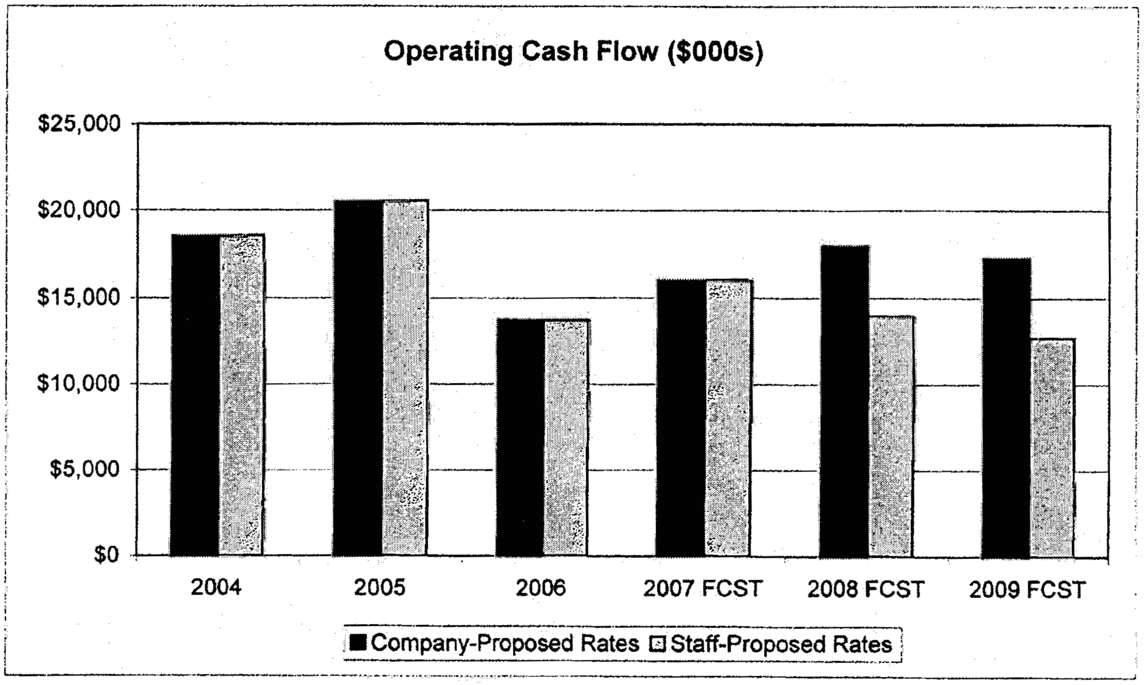
	Net Plant ($ Millions)	Customers	Investment per Customer
2003	$93	81,146	$1,147
2004	$103	85,464	$1,210
2005	$127	89,103	$1,427
2006	$157	92,917	$1,690
2007 Fcst.	$183	98,210	$1,863
2008 Fcst.	$209	103,822	$2,013
2009 Fcst.	$234	110,314	$2,121
<u>Compund Annual Growth Rates</u>			
2003-2006	19.0%	4.6%	13.8%
2006-2009 Fcst.	14.2%	5.9%	7.9%
<u>Absolute Growth</u>			
2003-2006	68.6%	14.5%	47.3%
2006-2009 Fcst.	49.0%	18.7%	25.5%

EXHIBIT

KCG-12

UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators





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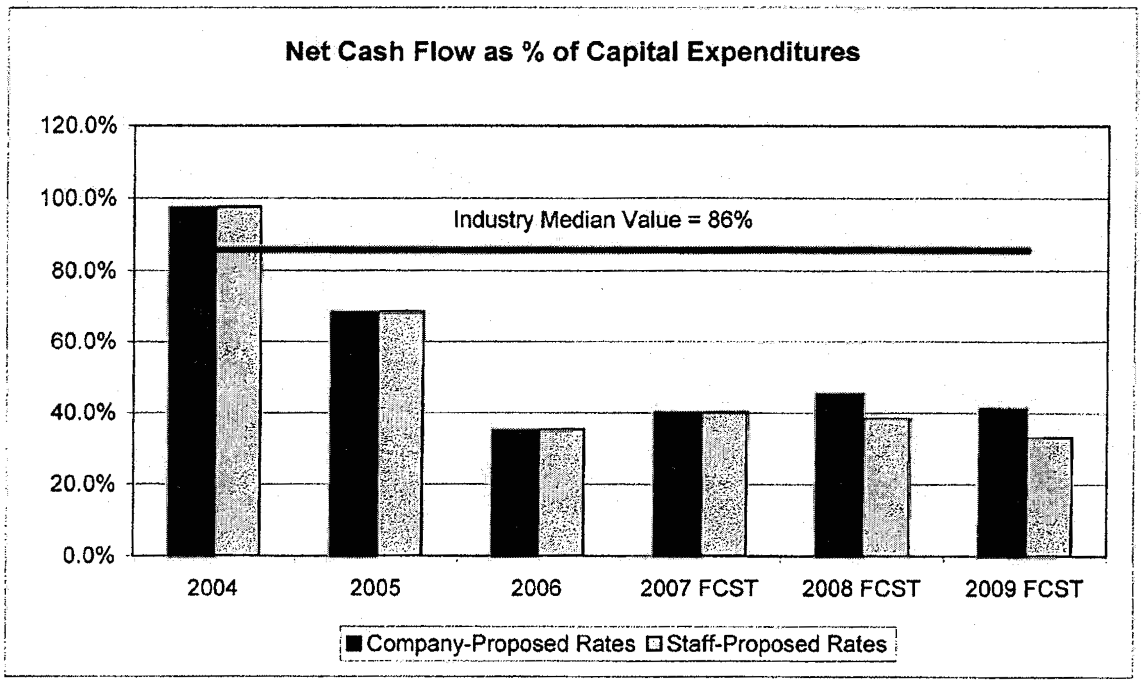
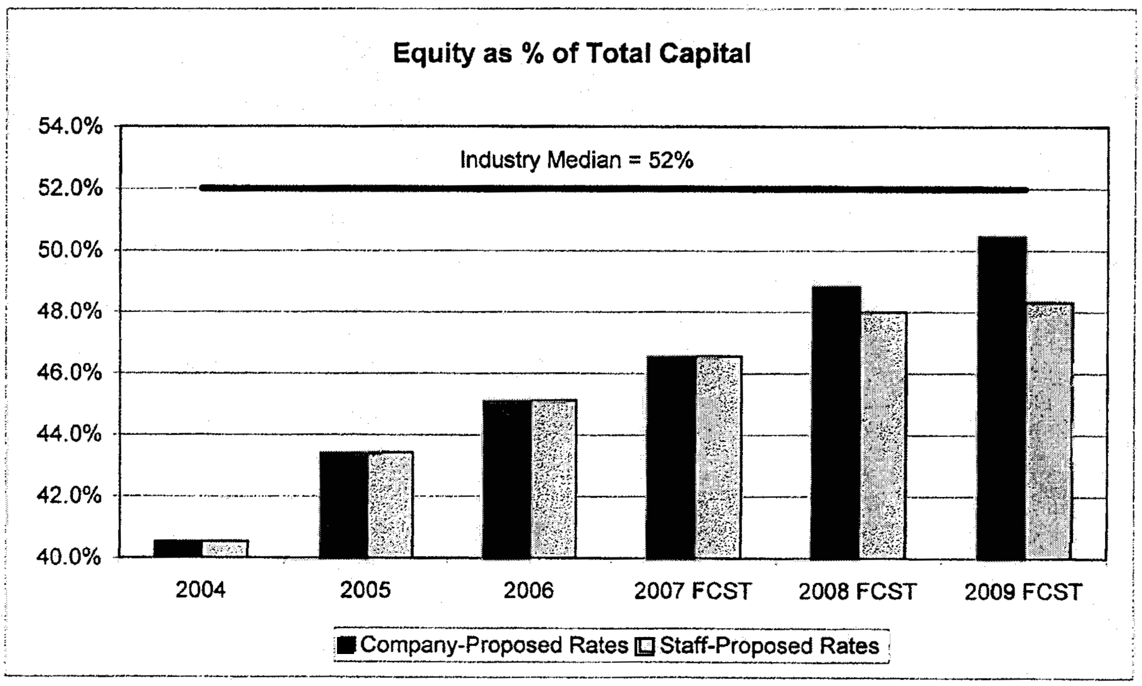
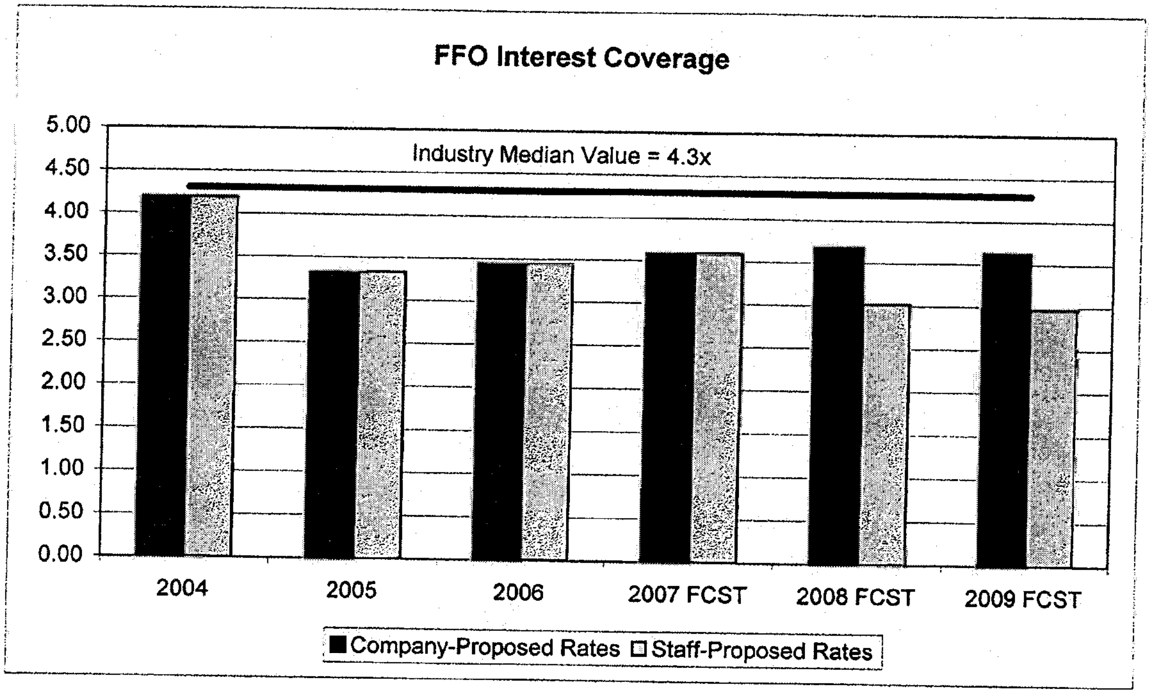
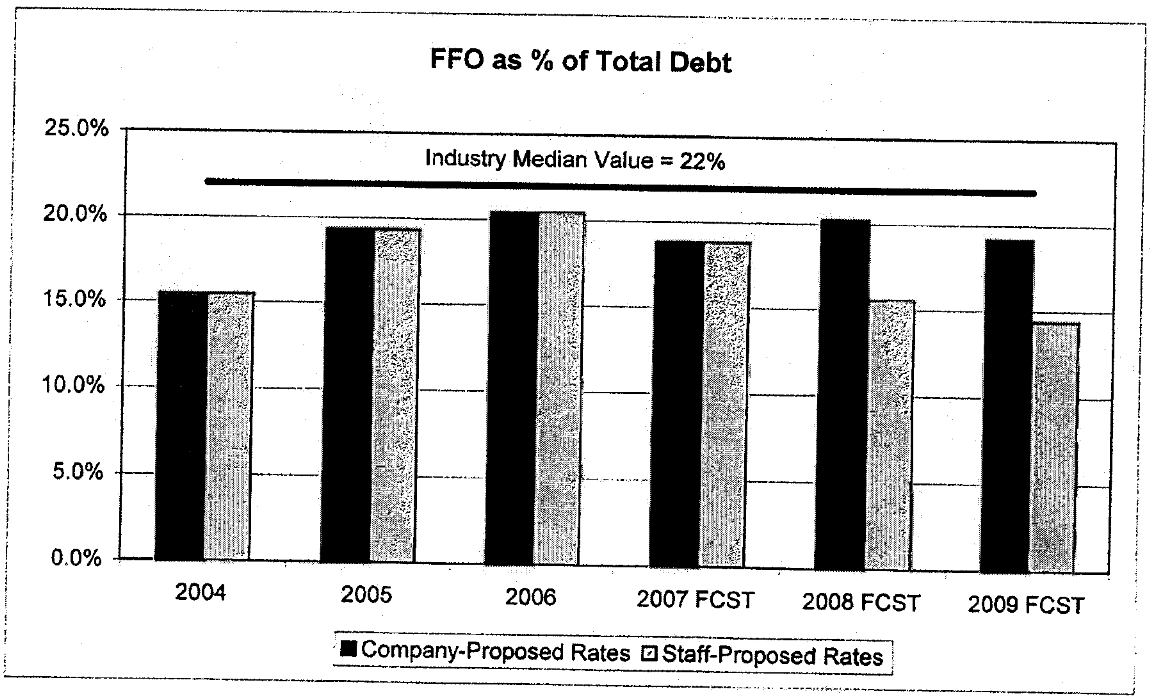




UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators

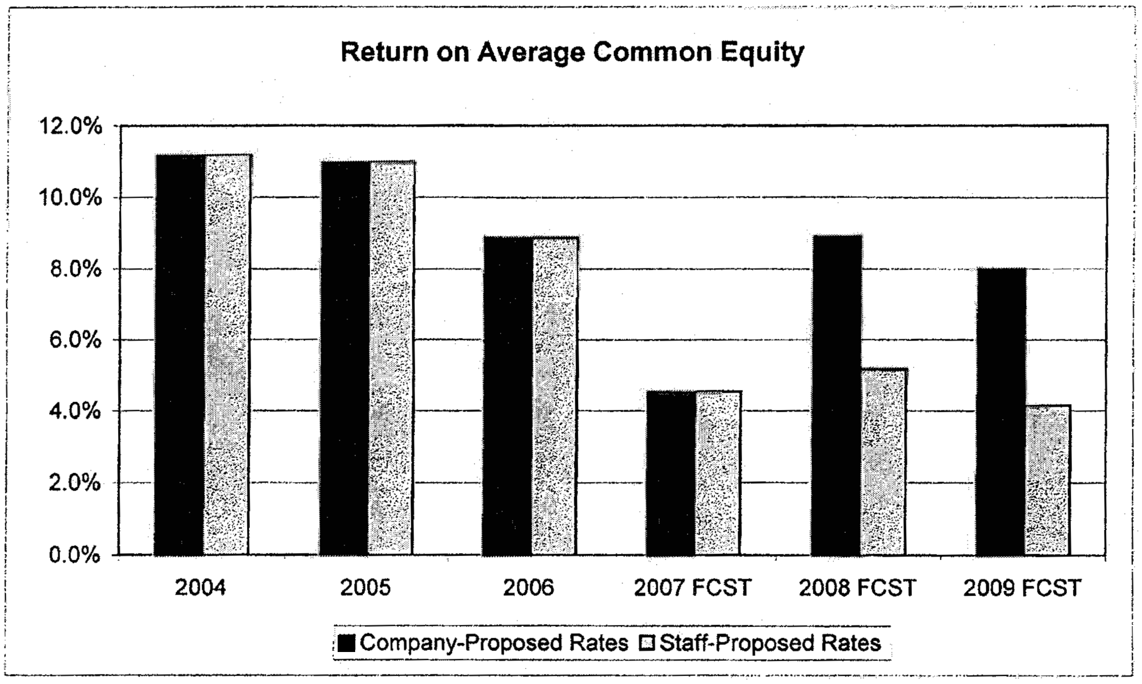


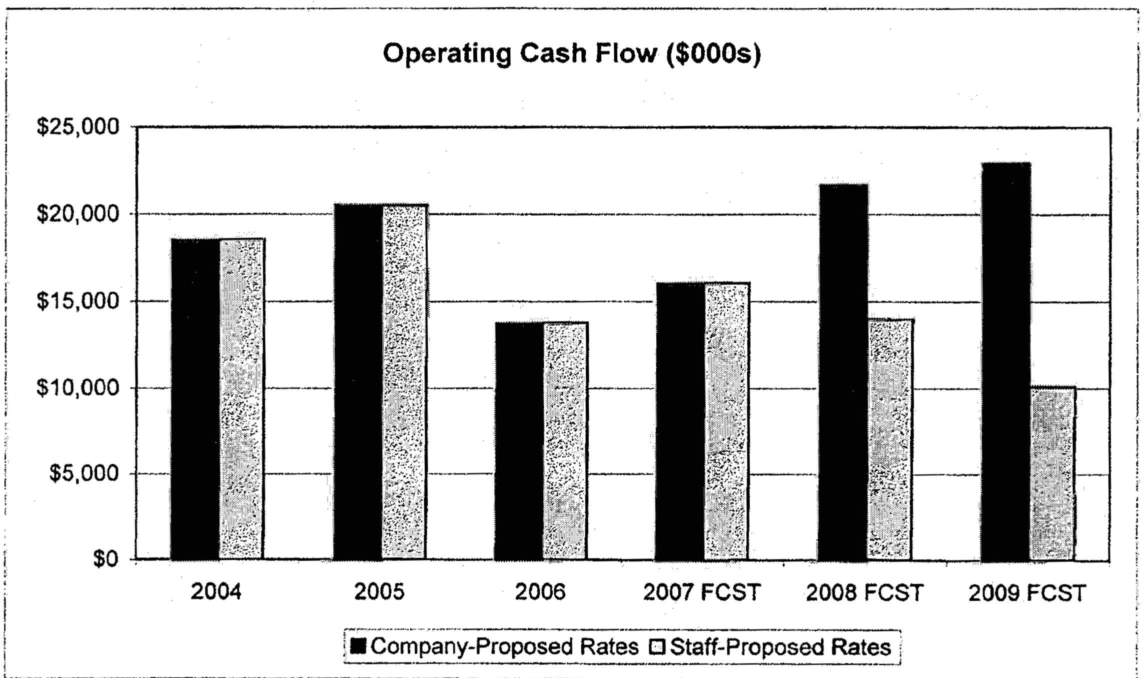


EXHIBIT

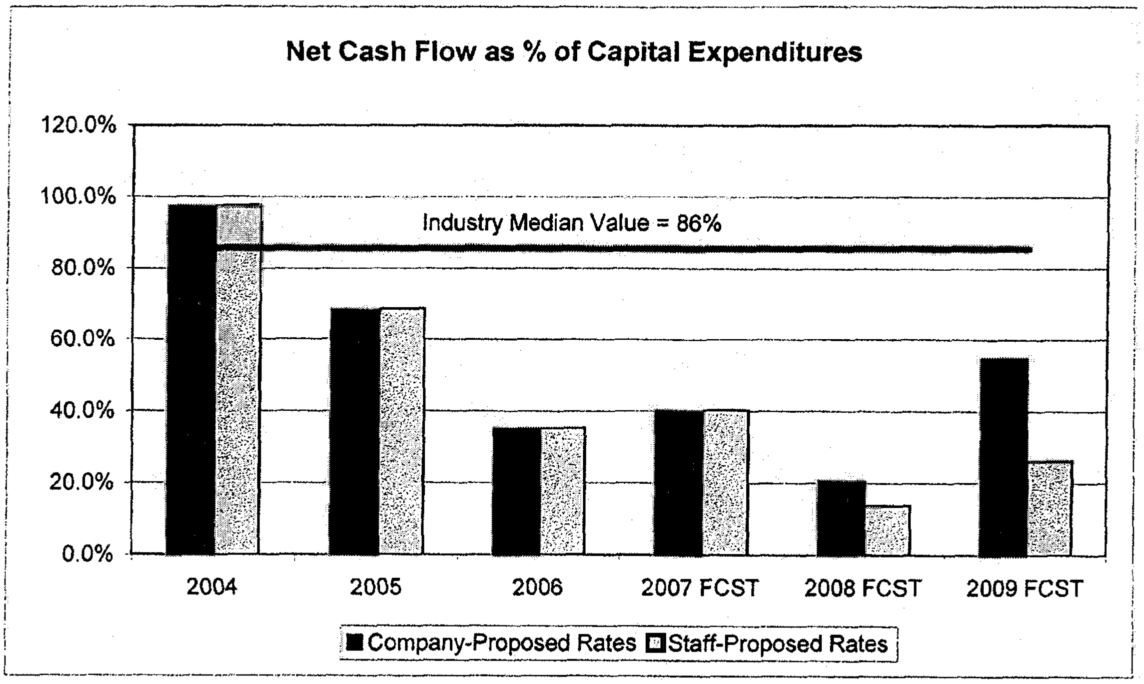
KCG-13

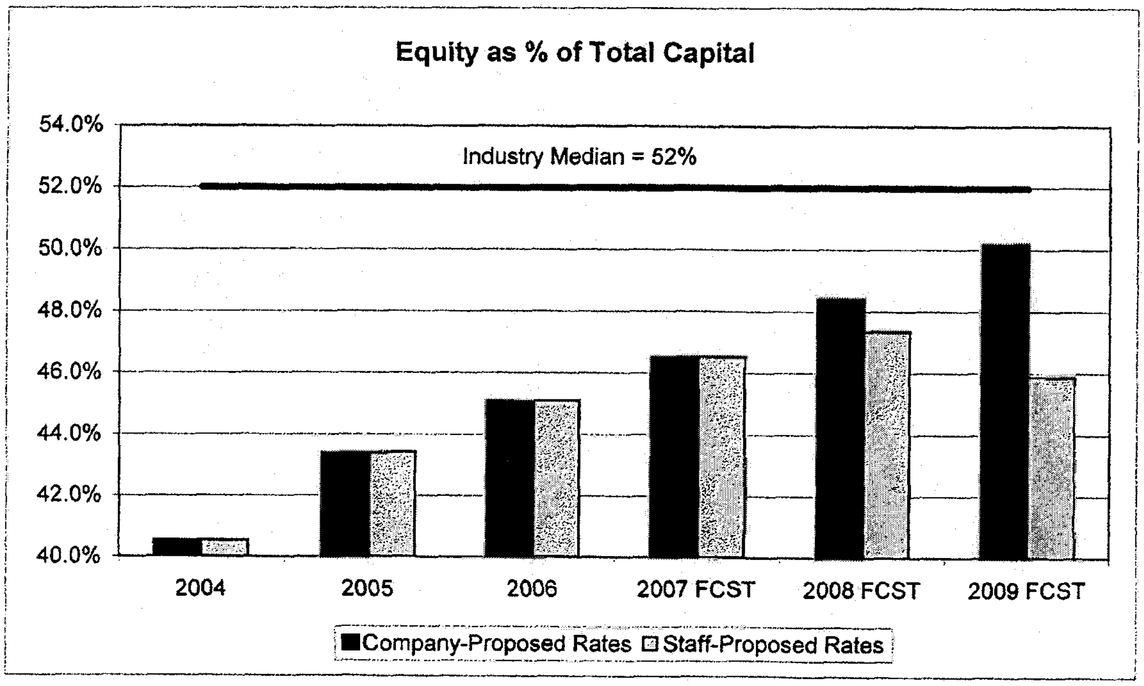
UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators with BMGS





UNS Electric, Inc.
Updated Financial Forecast with Company and Staff Rate Proposals
Summary of Key Financial Indicators with BMGS





UNS Electric, Inc.
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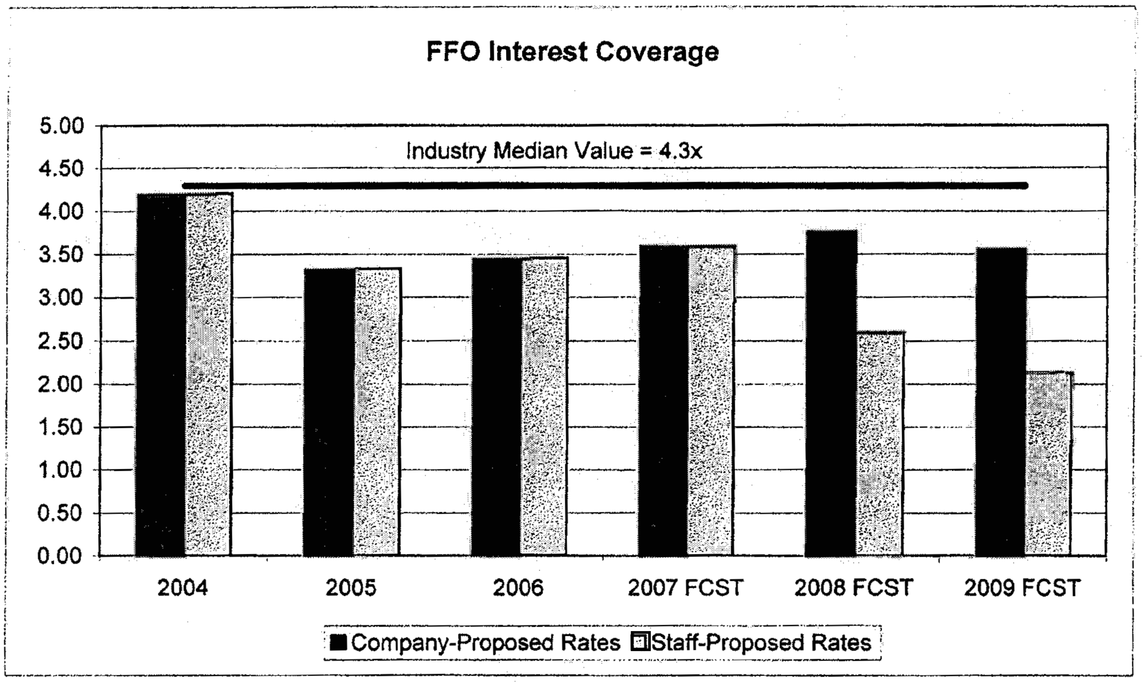

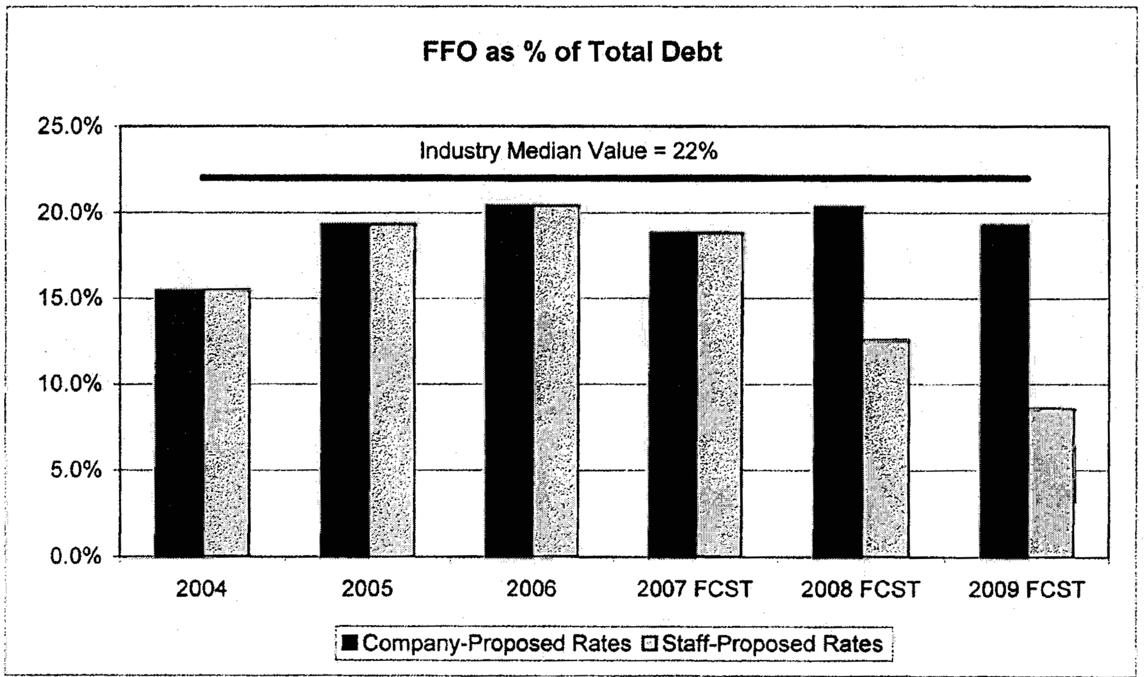

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783

Rejoinder Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

August 31, 2007

EXHIBIT
UNSE 36
Admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kentton C. Grant who filed Direct and Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to the Surrebuttal Testimony filed by the Commission Staff ("Staff") and the Residential Consumers Utility Office ("RUCO"). Specifically, I address the issues of financial integrity, the need for construction work in progress ("CWIP") in rate base, and the cost of capital to UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Please summarize your response to the Surrebuttal Testimony filed by Staff and RUCO.

A. Despite the volume of testimony filed on the issues of CWIP in rate base and the cost of capital, I found most of the testimony to be repetitive in nature, with only a few new arguments being offered by Staff and RUCO. No substantive analysis of UNS Electric's financial condition was provided, leading me to believe that financial integrity is not an issue of significant importance to either Staff or RUCO. This is unfortunate since UNS Electric will be required to attract large amounts of new capital over the next several years, the cost and availability of which will be greatly impacted by the outcome of this rate proceeding.

II. RESPONSE TO STAFF WITNESS RALPH C. SMITH'S SURREBUTTAL TESTIMONY.

Q. What issues raised by Mr. Smith in his Surrebuttal Testimony do you wish to address?

A. I will address the following issues raised by Mr. Smith: (i) his characterization of Staff's approach for calculating the rate of return (ROR) on fair value rate base ("FVBR"), (ii) his use of a "financial distress" standard for granting CWIP in rate base, (iii) his dismissal of other factors that point to the need for CWIP in rate base and (iv) his comments concerning regulatory lag and the appropriate use of financial forecasts in rate proceedings.

Q. On page 4 of his Surrebuttal Testimony, lines 4 through 7, Mr. Smith states that Staff's approach to calculating a ROR on FVRB "...cannot be dismissed as a mere superfluous mathematical exercise." Do you agree with this statement?

A. No, I do not. As I explained in my Rebuttal Testimony, Staff's approach is mathematically equivalent to the approach that was expressly disallowed by the Arizona Court of Appeals in a case involving Chaparral City Water Company. Despite his statement to the contrary, appearing on page 4 of his Surrebuttal Testimony (lines 1 through 4), Staff's approach does result in the same revenue requirement regardless of whether FVRB or original cost rate base ("OCRB") is used. It is only because of rounding that Staff has calculated a difference in the revenue requirement for UNS Electric. This $1,533 difference can be observed on Schedule A attached to Mr. Smith's Direct Testimony. This amount represents less than 0.001% of the $162 million revenue requirement identified by Staff, and only 0.04% of the $3.8 million revenue deficiency shown on Schedule A attached to Mr. Smith's Direct Testimony. Although I believe the Commission has wide discretion in setting a ROR on FVRB, Staff's approach is clearly unresponsive to the concerns raised in the Chaparral City Water Company ruling.

Q. Mr. Smith makes several references to "financial distress" in his discussion of the standard to be applied for granting CWIP in rate base. Is financial distress an appropriate standard to use?

A. No, it is not. According to a recent edition of Webster's unabridged dictionary, common definitions of "distress" include "an oppressed or distressed state, a painful situation, a state of danger or necessity, and an indication of weakness or incipient failure." Common synonyms include "suffering, misery, agony and dolor." To require a public utility to fall into such a financial state, before giving any consideration to CWIP in rate base or other ratemaking alternatives, is clearly inconsistent with the public interest. By the time a utility can demonstrate that it is in "financial distress," damage to the utility's credit and access to capital has already been done. The whole purpose of including CWIP in rate base is to support the utility's credit and access to capital, and to avoid the increased cost and reduced availability of capital associated with financial distress. If this same standard were applied in a medical setting, only those patients who become critically ill would be eligible for health care. By the time care is finally administered, it may be too late to save the patient.

Q. On page 12 of his Surrebuttal Testimony, lines 7 through 10, Mr. Smith states that "UNS Electric must show how it is different from the normal circumstances of a regulated public utility where CWIP has been excluded from rate base" and that it "has failed to do this." Do you agree with Mr. Smith on this point?

A. No, I do not. In both my Direct and Rebuttal Testimony I have provided extensive evidence concerning the negative financial impact of growth on UNS Electric and the extraordinary financial challenges facing this utility. I am not aware of any electric or gas utility whose growth in net plant investment comes close to approaching that of UNS Electric on a per customer basis – and Mr. Smith has not identified any such utilities. As demonstrated in Exhibit KCG-10 attached to my Rebuttal Testimony, this growth has a negative impact on the Company's financial results and highlights the need for timely and constructive rate relief. I am also not aware of any other electric utility that is facing the prospect of replacing 100% of its power supply and refinancing 100% of its long-term debt securities in the same year, a situation now faced by UNS Electric in 2008. If UNS Electric enjoyed healthy cash flows and an investment-grade credit rating going into this rate case, I could see how other parties might criticize a request to include CWIP in rate base. However, in light of the Company's strained cash flows and speculative-grade credit rating, it is disappointing that both Staff and RUCO oppose the Company's request to include CWIP in rate base.

Q. The inclusion of CWIP in rate base was recently considered and rejected by the Commission in the most recent Arizona Public Service Company ("APS") rate case. Can you point to any differences between the situation facing UNS Electric and that of APS?

A. Yes. Besides the obvious, such as size and financial wherewithal, there are several key differences that warrant examination. Based on my reading of Decision No. 69663 (June 28, 2007) – the opinion and order in the APS rate case – several factors were considered in rejecting the request for CWIP in rate base.

First, Staff was critical of the request because it was not presented in APS' Direct Testimony of APS, resulting in less time being available for discovery and analysis of the issue. That is not the case with UNS Electric, which included its request for CWIP in rate base in its original application and Direct Testimony.

Second, APS asked for CWIP in rate base in order to avoid being downgraded to a speculative-grade credit rating. UNS Electric already has a speculative-grade rating, and is attempting to improve its financial condition so it can eventually achieve an investment-grade credit rating.

Third, the financial forecast provided by APS was criticized because it included the results of operations for the transmission segment of its business, a sizable segment that falls under the rate jurisdiction of the Federal Energy Regulatory Commission ("FERC"). By contrast, due to the limited size and scope of its transmission assets, no wholesale transmission services are presently being provided by UNS Electric.

Lastly, Finding of Fact No.37 in Decision No. 69663 states that "APS failed to demonstrate that the near-term costs of customer growth are greater than the increased revenues generated by that growth." By contrast, I have presented clear evidence that the near-term cost of customer growth greatly exceeds the incremental revenues produced by that growth. In my Rebuttal Testimony on page 14, I described how Exhibit KCG-10 showed that new customers added approximately $1.2 million in annual delivery revenues for the year ending June 30, 2007 – while the Company's annual fixed costs increased by about $6.0 million. That means the Company experienced a $4.8-million increase in its annual revenue deficiency. Additionally, as demonstrated on Exhibit KCG-11 attached to my Rebuttal Testimony, the rate of growth in net plant investment at UNS Electric has exceeded that of APS – as well as that of Tucson Electric Power Company and Southwest Gas Corporation – by a substantial margin over the past three years on both an absolute and per-customer basis. The Company reemphasizes these key facts as Mr. Smith seemingly fails to recognize any of them in rejecting the Company's proposal.

Q. Do you have any comments regarding Mr. Smith's characterization of regulatory lag and the relevance of financial forecasts in the rate setting process?

A. Yes. Regarding the subject of regulatory lag, Mr. Smith appears to brush off any concerns over the time required to prepare and process a rate case by referring to past precedent and the existence of regulatory lag in other jurisdictions. On page 11 of his Surrebuttal Testimony, lines 11 through 15, Mr. Smith makes the following statement:

> "Regulatory lag refers to the difference in time between the test year and the rate effective date. My understanding is that it has always existed as an integral part of rate of return-based public utility regulation in Arizona, and for that matter virtually all states. It is not a new phenomenon which would require a change in basic regulatory policy."

While I agree with Mr. Smith that regulatory lag is a common phenomenon in many rate jurisdictions, he fails to recognize that changes to "basic regulatory policy" are sometimes warranted due to changing circumstances. Due to a rapidly expanding population and increasing electrical demands, electric utilities in Arizona, including UNS Electric, are struggling to cope with a surge in new transmission and distribution plant investment. At the same time, the regulatory lag period referred to by Mr. Smith is significantly longer in Arizona relative to that experienced in most other states. Even so, and as I indicated in Rebuttal Testimony, many other rate jurisdictions include CWIP in rate base.

The timeliness of cost recovery by utilities is also receiving renewed attention by the major credit rating agencies. For example, in an August 2007 publication entitled "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," Moody's Investors Service had the following observations:

> "...there are concerns arising from the sector's sizable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention. Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more frequent requests for rate relief could create pressure for future incremental rate relief from regulators, or at a minimum, raise the uncertainty level associated with expected recoveries – thereby directly affecting one of our primary rating drivers." (See page 1 of the Moody's publication, attached as Exhibit KCG-14.)

. . .

> "In our opinion, the rising costs and investment needs will have a direct impact on all three financial statements: income, cash flow and balance sheet. As a result, one of the biggest challenges for utility companies will be to seek and receive timely recovery of prudently incurred expenses. In addition, the substantial increases in capital expenditures will have a material impact on the sector's ability to generate free cash flow. While Moody's recognizes that the utility sector usually operates in a negative free cash flow environment, a concern could be raised if the level of negative free cash flow became large enough, or if regulatory lag was long enough, that the leverage were to increase materially." (See page 3 to Exhibit KCG-14.)

In the case of UNS Electric, assuming new rates are implemented in January 2008, the regulatory lag period will have lasted approximately 18 months from the test year ended June 30, 2006. From a financial perspective, that is a long time to wait when the cost of customer growth greatly exceeds the incremental revenues derived from that growth. Regarding the use of financial forecast information, Mr. Smith cautions against using such information in this proceeding. Starting on page 10 of his Surrebuttal Testimony at line 23, Mr. Smith makes the following statement:

> "To the extent that Mr. Grant is attempting to use his revised financial forecasts as some kind of surrogate for a future test year, or as some kind of test of the reasonableness of the parties' differing recommendations, his comparisons to not appear to reflect the adjustments to rate base or expenses that contribute to Staff recommending a different level of revenue increase than has been requested by the Company."

I have two concerns with this statement. First, it appears that Mr. Smith may have misinterpreted the Company's intent regarding the use of financial forecast information. Second, he suggests that further adjustments to the financial forecasts are warranted, when in fact no such adjustments are warranted.

Q. Please explain.

A. Certainly. While UNS Electric would certainly support the opportunity to eliminate regulatory lag through the use of a future test year, the Company is fully aware of the fact that Arizona relies on a historical test year for setting rates. That is exactly what the Company used here. The test year ended June 30, 2006 formed the basis for UNS Electric's rate request, including known and measurable adjustments thereto, and the CWIP balance being requested in this case reflects the amount outstanding as of that date. There is simply no merit to Mr. Smith's insinuation that the Company's financial forecasts are being used somehow as a "surrogate" for a future test year. Rather, the financial forecasts are a necessary *component* to determining just and reasonable rates and a fair ROR on the Company's historical test year rate base.

Regarding the Company's use of financial forecast information to "test the reasonableness of the parties' differing recommendations," Mr. Smith is absolutely correct in making this assumption. Financial forecast information is invaluable in determining whether or not CWIP is needed in rate base to support a utility's financial integrity. This information is also helpful in ensuring that the allowed ROR and overall level of rate relief will be sufficient to support the utility's credit and access to capital. Mr. Smith errs, however, in his insistence that financial forecast information be adjusted to reflect the rate base and cost disallowances recommended by Staff and other parties. It is simply unrealistic to think that future costs will disappear just because ratemaking adjustments are made to historical test year costs. Additionally, the largest difference between the Company and Staff in terms of revenue requirement relates to CWIP in rate base and the allowed ROE, two items that only affect revenues on a going-forward basis. Since the financial forecasts presented in my Direct and Rebuttal Testimonies reflect the best estimates of management, and are consistent with the internal operating and capital budget outlooks prepared for the Company, there is no basis for adjusting these forecasts as suggested by Mr. Smith.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Smith?

A. Yes, it does.

III. RESPONSE TO STAFF WITNESS DAVID C. PARCELL'S SURREBUTTAL TESTIMONY.

Q. What comments do you have on the Surrebuttal Testimony of Mr. Parcell?

A. My comments will be brief, as most of the points raised by Mr. Parcell on the cost of capital were addressed in my Rebuttal Testimony. However, I feel compelled to comment on his misunderstanding of the relationship between UNS Electric and its parent company, UniSource Energy Corporation ("UniSource Energy").

Q. What misunderstanding are you referring to?

A. Mr. Parcell continues to believe that UNS Electric somehow derives most of its financial strength from UniSource Energy. In discussing the cost of capital to UNS Electric on pages 4 and 5 of his Surrebuttal Testimony, Mr. Parcell makes numerous references to the Company's corporate affiliates including UniSource Energy, Tucson Electric Power Company ("TEP"), UNS Gas, Inc. ("UNS Gas") and UniSource Energy Services ("UES"), the intermediate holding company that owns both UNS Electric and UNS Gas. He cites the financial linkages between UNS Electric and its parent companies, as well as the decision not to merge UNS Electric into TEP, as reasons for dismissing the company-specific risks facing UNS Electric. In doing so, I believe that Mr. Parcell has confused the risk of investing in UNS Electric with the risk of investing in UniSource Energy, and has subtly attempted to shift the issue of financial integrity to the parent company and away from the operating utility where it rightfully belongs.

Q. Please describe the linkages between UNS Electric and its corporate affiliates.

A. UNS Electric is a public service corporation owned by UES, an intermediate holding company owned by UniSource Energy. Due to lender requirements, UES provided a guarantee for the repayment of long-term debt and credit facility borrowings at both UNS

Electric and UNS Gas. Other than the UES guarantee, no other guarantees have been provided to UNS Electric by any corporate affiliate including UniSource Energy. UNS Electric is a separate corporation having its own assets and obligations that are clearly segregated from its affiliates. It is responsible for procuring purchased power, natural gas and other materials and services on its own credit. And although UES has guaranteed the Company's long-term debt and credit facility borrowings, UNS Electric's debt securities were rated separately from UNS Gas and received different terms and conditions when the existing long-term notes were issued in 2003. The only other corporate transactions between UNS Electric and its affiliates involve the provision of administrative and operating support services by TEP, the participation by UNS Electric in a consolidated tax sharing agreement, and the infusion of additional equity capital from time to time by UniSource Energy and UES. Although these linkages and corporate affiliations serve to strengthen the financial standing of UNS Electric, they are clearly limited in terms of their scope and size.

Q. On page 5 of his Surrebuttal Testimony, lines 1 through 4, Mr. Parcell refers to a potential merger of UNS Electric with TEP as a means of reducing the cost of capital to UNS Electric. Is such a merger feasible?

A. No, it is not. As indicated in the response to Staff Data Request No. STF 4.7, TEP is an issuer of tax-exempt local furnishing bonds, of which $359 million are currently outstanding. An additional $221 million of local furnishing bonds that were repurchased in 2005 also remain eligible for re-issuance. As an issuer of local furnishing bonds TEP is restricted to providing retail service within a two-county area. If UNS Gas or UNS Electric were to merge with TEP, TEP would no longer qualify as an issuer of local furnishing bonds, thereby causing the redemption or defeasance of these low cost bonds. As a consequence, TEP would experience a substantial increase in its cost of debt. Since this would clearly not be in the interest of TEP or its customers, the merger scenario referenced by Mr. Parcell is simply not feasible at this time.

Q. Is the linkage between UNS Electric and its other corporate affiliates relevant to an assessment of financial integrity and cost of capital?

A. No, it is not. Unless the utility has somehow been harmed as a result of the parent/subsidiary relationship, which is clearly not the case for UNS Electric, the issue of who owns the utility is largely irrelevant. The cost of capital is a function of the risk to which it is exposed, and not on the identity of the investor providing capital. Likewise, it is the utility that is responsible for providing service and attracting the capital and other resources needed to provide that service, and not the parent company holding an equity interest in the utility. Although a substantial portion of UNS Electric's capital has obviously come from UniSource Energy in the form of equity contributions, as well as from the retention of earnings that otherwise could have been paid out as dividends, this continuing financial support is clearly premised on the ability of UNS Electric to earn a reasonable ROR on its invested capital.

Q. Does that conclude your response to Mr. Parcell's Surrebuttal Testimony?

A. Yes, it does.

IV. <u>RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ'S SURREBUTTAL TESTIMONY.</u>

Q. What comments do you have on the Surrebuttal Testimony of Ms. Diaz Cortez?

A. Since I did not find any new arguments on the issue of CWIP in rate base in the Surrebuttal Testimony of Ms. Diaz Cortez, I have no further comments to make. I would instead refer to the Rebuttal Testimony I filed earlier in response to Ms. Diaz Cortez' Direct Testimony, and to my earlier response in this Rejoinder Testimony to Mr. Smith, whose arguments overlap with those of Ms. Diaz Cortez.

Q. Does that conclude your response to Ms. Diaz Cortez' Surrebuttal Testimony?

A. Yes, it does.

V. <u>RESPONSE TO RUCO WITNESS WILLIAM RIGSBY'S SURREBUTTAL TESTIMONY.</u>

Q. Do you have any comments on the Surrebuttal Testimony filed by Mr. Rigsby?

A. Yes, I do. I will focus my comments on the following issues: (i) Mr. Rigsby's interpretation of recent developments in the financial markets, (ii) his continued justification of abnormally low growth rates in the discounted cash flow ("DCF") model, (iii) his dismissal of regulatory lag and the impact of growth on UNS Electric and (iv) his conclusion regarding the sufficiency of RUCO's rate recommendation in light of the *Hope* and *Bluefield* court decisions.

Q. Does Mr. Rigsby discuss recent developments in the financial markets?

A. Yes, he does. On pages 6 through 8 of his Surrebuttal Testimony he discusses the recent turmoil experienced in the financial markets. In his discussion he refers to recent "borrowing crises," "a turbulent week on Wall Street" and markets that may "fail to settle down." (See page 7 of his Surrebuttal Testimony, lines 1, 4 and 11.) At the end of this discussion, on page 8 of his Surrebuttal Testimony, he then points to a recent reduction in the yield on U.S. Treasury Bills as a reason for reducing the cost of equity estimate obtained from his application of the Capital Asset Pricing Model ("CAPM").

Q. Do you concur with Mr. Rigsby's observations and conclusions?

A. While I certainly agree with his observation that the financial markets have been in a state of turmoil over the past several weeks, I disagree with his conclusion that the cost of equity for UNS Electric would somehow decrease as a result of this turmoil. What Mr. Rigsby has observed is a re-pricing of risk in the financial markets, with a flight to quality by investors that has benefited U.S. Treasury securities and pummeled most other financial assets. Although he is correct in pointing out the substantial reduction in required yields on short-term U.S. Treasury securities, Mr. Rigsby failed to mention the substantial increase in required risk premiums that has occurred in the corporate debt and equity markets. Such an increase, in my opinion, would more than offset any reduction to U.S. Treasury yields when updating a risk premium model such as the CAPM.

Q. How has this recent financial turmoil affected the required risk premiums on utility securities?

A. The risk premiums demanded by investors have increased substantially. The best evidence of this is the widening of credit spreads, or the difference in required rates of return on long-term utility bonds and long-term U.S Treasury bonds. Based on market data available through Reuters financial service, the average credit spread for ten-year utility bonds having a Triple-B credit rating (Baa or BBB) widened from 141 basis points to 178 basis points between September 29, 2006 (the date referenced on page 20 of my Direct Testimony) and August 23, 2007. This increase of 37 basis points (0.37%) reflects the increased risk premium now required by investors for these bonds. Consistent with the previously mentioned flight to quality, the impact on speculative-grade utility bonds has been much more severe. The observed credit spread for ten-year utility bonds having a Double-B credit rating (Ba or BB) widened from 220 basis points to 345 basis points over this same period, an increase of 125 basis points (1.25%). Since the required yield on ten-year U.S. Treasury bonds has dropped by only 2 basis points (0.02%) over this same period of time, it is apparent that the cost of both debt and equity capital for utilities with speculative-grade ratings has increased substantially since my Direct Testimony was filed.

This disproportionate increase to the cost of capital, relative to investment-grade utilities, also demonstrates the prudence of targeting and maintaining an investment-grade credit rating for UNS Electric.

Q. What comments do you have regarding Mr. Rigsby's discussion of long-term DCF growth rates?

A. Mr. Rigsby dedicates nearly five pages of his Surrebuttal Testimony to a defense of the dividend growth rates used in his constant growth DCF model and to a further critique of the growth rates used in my multi-stage DCF model. Regardless of whether the constant growth or multi-stage version of the DCF model is used, it is obvious that the results obtained are highly sensitive to the growth rates selected. Unfortunately, as discussed in my Rebuttal Testimony, Mr. Rigsby's use of abnormally low growth rates results in cost of equity estimates as low as 6.6% for his comparable company group. By contrast, my use of five-year growth rates reflecting company-specific projections, followed by the use of an industry-wide growth rate that closely approximates the expected long-term growth rate in the U.S. economy, results in cost of equity estimates that are much more reasonable when compared with (i) recent ROE allowances for other electric utilities, (ii) required yields on investment-grade utility bonds and (iii) the results that Mr. Rigsby and I obtained for the same group of companies using the CAPM. For this reason, I recommend once again that Mr. Rigsby's DCF analysis be given little or no weight in this proceeding.

Q. On page 15 of his Surrebuttal Testimony, lines 1 through 10, Mr. Rigsby downplays the significance of regulatory lag and growth for UNS Electric. Does he offer any new arguments on this subject?

A. No, he does not. However, on page 16 of his Surrebuttal Testimony, lines 1 through 11, he now cites a probable slowing of growth in Mohave County as a positive factor for UNS Electric.

Q. Do you agree that a slowing of growth in the Company's service territory would be a positive development for UNS Electric?

A. If a slowdown in customer growth were accompanied by a reduction in capital spending, then I would agree with Mr. Rigsby on this point. However, based on preliminary planning for fiscal years 2008 through 2012, it does not appear that capital spending for UNS Electric will decrease even if a decline in customer growth occurs. The primary reason for this is the increased cost of system reinforcement work that UNS Electric is now planning for. As a result, the financial forecasts presented in my Direct and Rebuttal Testimony may be overly optimistic. If a significant slowdown in customer and sales growth occurs, with no commensurate decrease to the Company's capital spending requirements, the end result would be lower earnings and cash flow relative to the forecasts previously presented.

Q. On page 15 of his Surrebuttal Testimony, Mr. Rigsby states his belief that RUCO's rate recommendation will satisfy the capital attraction standards set forth in the *Hope* and *Bluefield* decisions. What evidence does he offer in this regard?

A. The only evidence I could find was on page 15, lines 14 through 16, where he states that "RUCO believes that the rates it is recommending in this case will provide the Company with the opportunity to recover its operating expenses and provide a return on its invested capital." Unfortunately, I could find no other analysis or discussion in his testimony regarding the *adequacy* of that return. As discussed in my Rebuttal Testimony, RUCO's rate recommendation is expected to result in an earned ROE of only 2.6% in 2008 assuming a full year of rate relief. This expected return is so low that it cannot even compete with the 4.09% risk-free rate on U.S. Treasury bills cited by Mr. Rigsby on page 8, line 7 of his Surrebuttal Testimony. Under RUCO's rate recommendation, UniSource Energy would be better off investing in short-term U.S. Treasury bills than investing additional equity capital in UNS Electric.

Q. Does that conclude your Rejoinder Testimony?

A. Yes, it does.

EXHIBIT

KCG-14

Special Comment

August 2007

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Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector

Summary

While the rating outlooks for the vast majority of the North American regulated electric utility companies remain stable, a number of "storm clouds" appear to be gathering on the horizon which could have negative credit implications over the intermediate-term. The stable outlook is primarily based on the consistency of key financial credit ratios reported over the past few years, an expected continuation of relatively strong financial metrics over the next 6 to 18 months, our views regarding timely regulatory recoveries of prudently incurred costs and investments and an overall focus on regulated operations by management. One of the most significant factors incorporated into our outlook is a view that most utility management teams will maintain healthy and constructive relationships with their state regulatory authorities and that most state regulatory authorities prefer to regulate financially healthy utilities within their states.

However, there are concerns arising from the sector's sizable infrastructure investment plans in the face of an environment of steadily rising operating costs. Combined, these costs and investments can create a continuous need for regulatory rate relief, which in turn can increase the likelihood for political and/or regulatory intervention. Conceivably, the combination of rising costs, higher infrastructure investment needs and larger or more frequent requests for rate relief could create pressure for future incremental rate relief from state regulators, or at a minimum, raise the uncertainty level associated with expected recoveries — thereby directly affecting one of our primary rating drivers. This potential for increased regulatory uncertainty and pressure for rate relief might peak several years from now, at precisely the time when many companies are completing their base-load generation construction projects or other non-discretionary infrastructure investment projects and the potential for rate shock to consumers would be highest.

Moody's Investors Service
Global Credit Research

Furthermore, despite the clear and present challenges currently facing the industry over the near, intermediate and longer-term horizons, some utility parent holding companies continue to pursue overly biased shareholder reward policies in the form of high dividend payout targets, annual dividend rate increases and common equity repurchase programs. While these financial policies may be rooted in capital efficiency philosophies, and companies obviously work for shareholders, Moody's observes that these shareholder reward strategies are currently being established in the face of increasing business and operating risks that are clearly articulated in the public SEC disclosures, and, in our opinion, typically result in a permanent increase to leverage and fixed obligations. If utility companies experience construction cost overruns, lengthy delays, quasi-permanent recovery deferrals or other adverse regulatory rulings, a deterioration of credit quality could result. Should this situation materialize, Moody's would be concerned over the potential prospect that regulators may harbor little sympathy for companies seeking financial relief if they previously chose a policy that overly benefited shareholders, given the lost opportunity costs associated with strengthening a balance sheet.

Moody's acknowledges the longer-term aspect of the risks associated with these storm clouds and the uncertainty associated with potential downside scenario assessments. At this time, the unknowns associated with the investment plans and regulatory relationships are not sufficient enough to cause direct implications to near-term credit ratings. However, Moody's will continue to assess the constructiveness of the regulatory relationships between utility companies and their respective regulatory commissioners. In our opinion, the relationships with regulators could conceivably counterbalance any potential deterioration of key financial credit ratios, especially if the deterioriation is expected to be relatively temporary. In addition, Moody's expects most utility companies to approach their financing plans with a balanced mix of debt and equity to fund their capital expenditures. If however, the business and operating risks for a utility appear to be increasing at a more significant pace, or the regulatory relationships appear to take a more adversarial tone, the rating outlook would likely change, even if the key financial credit ratios were maintained at current levels.

In this Special Comment, Moody's will explore several of these downside risks to credit quality and articulate our views regarding these risks and how we may incorporate them into our credit analysis.

Summary of Rising Business and Operating Risks

The storm clouds referenced in this report essentially point to a potential increase in the business and operating risk profile for the sector. In our opinion, the rising costs and investment needs will have a direct impact on all three financial statements: income, cash flow and balance sheet. As a result, one of the biggest challenges for utility companies will be to seek and receive timely recovery of prudently incurred expenses. In addition, the substantial increases in capital expenditures will have a material impact on the sector's ability to generate free cash flow. While Moody's recognizes that the utility sector usually operates in a negative free cash flow environment, a concern could be raised if the level of negative free cash flow became large enough, or if regulatory lag was long enough, that the leverage were to increase materially. Furthermore, shareholder dividends could conceivably begin to outpace earnings growth, if the regulatory relationship were to become more confrontational.

Income Statement	Revenues	Will rate relief stay current given potential for rising regulatory/political intervention?
	Fuel & Purchased Power	Rising – need for timely recovery
	Operations & Maintenance	Rising expenses to maintain existing assets
	SG&A	Rising – healthcare / work force
	Interest	What happens to interest rates?
	Taxes	Rising
Cash Flow Statement	Net income	Rising with rate relief and attempts for cost containment
	Depreciation & Amortization	Lower than capital expenditures
	Working Capital/Other	Impact of deferred costs / Liquidity impact
	Capital Expenditures	Rising significantly (plus environmental compliance risk)
	Dividends	Rising. Consistent with earnings. A fixed obligation.
Balance Sheet	Regulatory Assets	Increasing
	Debt	Rising – to fund negative FCF
Increasing regulatory / political intervention risks		
Increasing risks associated with environmental compliance/ Carbon legislation		

Comparable Company Analysis

Moody's regularly utilizes comparable company analysis as part of our fundamental credit research, which we typically refer to as peer groups. These peer groups can be created based on a specific rating category (for example, all Baa1 parent holding companies) or by business composition (for example, all transmission and distribution "T&D" utilities). In this Special Comment, Moody's will summarize the financial results of a much broader peer group than we would typically use for a specific rated entity. In addition, we acknowledge that there may be occasions where a particular company's extraordinary event may skew an annual average (which we may not adjust for), so we have attempted to minimize the effect by also assessing a 5-year average and a 4-year Compound Annual Growth Rate (CAGR) from 2002 to 2006.

The companies included in the peer groups for the bulk of this Special Comment are listed in the tables below. The companies that comprise any additional peer groups, which include companies characterized by region or other industrial, non-utility peer groups, are listed in Appendix A.

Utility Parent Companies	Senior Unsecured Rating*
Allegheny Energy, Inc.	Ba2
ALLETE, Inc.	Baa2
Ameren Corporation	Baa2
American Electric Power Company	Baa2
Aquila, Inc.	Ba3
Avista Corp.	Ba1
Black Hills Corporation	Baa3
Central Vermont Public Service Co.	Ba2**
Cinergy Corp.	Baa2
Cleco Corporation	Baa3
CMS Energy Corporation	Ba1
Constellation Energy Group, Inc.	Baa1
Dominion Resources Inc.	Baa2
DPL Inc.	Baa3
DTE Energy Company	Baa2
Duke Energy Corporation	Baa2
Duquesne Light Holdings, Inc.	Ba1
E. ON U.S. LLC	A3
Edison International	Baa2
El Paso Electric Company	Baa2
Empire District Electric Company	Baa2
Entergy Corporation	Baa3
Exelon Corporation	Baa2
FirstEnergy Corp.	Baa3
FPL Group, Inc.	(P)A2
Great Plains Energy Incorporated	(P)Baa2
Hawaiian Electric Industries, Inc.	Baa2
IDACORP, Inc.	Baa2
Integrys Energy Group, Inc.	A3
IPALCO Enterprises, Inc.	Ba1***
MidAmerican Energy Holdings Co.	Baa1
OGE Energy Corp.	Baa1
Otter Tail Corporation	A3
Pepco Holdings, Inc.	Baa3
PG&E Corporation	Baa3
Pinnacle West Capital Corporation	Baa3
PNM Resources, Inc.	Baa3
PPL Corporation	Baa2
Progress Energy, Inc.	Baa2
PSEG Energy Holdings L.L.C.	Ba3
Public Service Enterprise Group	Baa2
Puget Energy, Inc.	Ba1
SCANA Corporation	A3
Sempra Energy	Baa1
Sierra Pacific Resources	B1
Southern Company (The)	A3
TECO Energy, Inc.	Ba1
TXU Corp.	Ba1
TXU US Holdings Company	Baa3
UniSource Energy Corporation	Ba1***
Westar Energy, Inc.	Baa3
Wisconsin Energy Corporation	A3
Xcel Energy Inc.	Baa1

** Long-term Issuer Rating used where Senior Unsecured is not available.*
*** Preferred Stock*
**** Senior Secured*
***** First Mortgage Bond*

Integrated Utilities	Senior Unsecured Rating*
Alabama Power Company	A2
Appalachian Power Company	Baa2
Arizona Public Service Company	Baa2
Black Hills Power, Inc.	Baa2
Central Illinois Light Company	Ba1
Cleco Power LLC	Baa1
Columbus Southern Power Company	A3
Consumers Energy Company	(P)Baa2
Dayton Power & Light Company	Baa1
Detroit Edison Company (The)	Baa1
Duke Energy Carolinas, LLC	A3
Duke Energy Indiana, Inc.	Baa1
Duke Energy Ohio, Inc.	Baa1
Entergy Arkansas, Inc.	Baa2
Entergy Gulf States, Inc.	Baa3****
Entergy Louisiana, LLC	Baa2
Entergy Mississippi, Inc.	Baa3
Entergy New Orleans, Inc.	Ba2
Florida Power & Light Company	A1
Georgia Power Company	A2
Green Mountain Power Corporation	Baa1****
Gulf Power Company	A2
Hawaiian Electric Company, Inc.	Baa1
Idaho Power Company	Baa1
Indiana Michigan Power Company	Baa2
Indianapolis Power & Light Company	Baa2
Interstate Power and Light Company	A3
Kansas City Power & Light Company	A3
Kansas Gas & Electric Co.	Baa2***
Kentucky Power Company	Baa2
Kentucky Utilities Co.	A2
Louisville Gas & Electric Company	A2
Madison Gas and Electric Company	Aa3
MidAmerican Energy Company	A2
Mississippi Power Company	A1
Monongahela Power Company	Baa3
Nevada Power Company	B1
Northern States Power Company (MN)	A3
Northern States Power Company (WI)	A3
Ohio Power Company	A3
Oklahoma Gas & Electric Company	A2
Pacific Gas & Electric Company	Baa1
PacifiCorp	Baa1
Portland General Electric Company	Baa2
Progress Energy Carolinas, Inc.	A3
Progress Energy Florida, Inc.	A3
Public Service Company of Colorado	Baa1
Public Service Company of New Hampshire	Baa2
Public Service Company of New Mexico	Baa2
Public Service Company of Oklahoma	Baa1
Puget Sound Energy, Inc.	Baa3
Savannah Electric and Power Company	A2
Sierra Pacific Power Company	B1
South Carolina Electric & Gas Company	A2
Southern California Edison Company	A3
Southwestern Electric Power Company	Baa1
Southwestern Public Service Company	Baa1
Tampa Electric Company	Baa2
Tucson Electric Power Company	Baa3
Union Electric Company	Baa1
Virginia Electric and Power Company	Baa1
Wisconsin Electric Power Company	A1
Wisconsin Power and Light Company	A2
Wisconsin Public Service Corporation	A1

T&D Utilities	Senior Unsecured Rating*
AEP Texas Central Company	Baa2
AEP Texas North Company	Baa1
Atlantic City Electric Company	Baa1
Baltimore Gas and Electric Company	Baa2
CenterPoint Energy Houston Electric	Baa3
Central Hudson Gas & Electric Co	A2
Central Illinois Light Company	Ba1
Central Illinois Public Service	Ba1
Central Maine Power Company	A3
Cleveland Electric Illuminating	Baa3
Commonwealth Edison Company	Ba1
Connecticut Light and Power Company	Baa1
Consolidated Edison Company of NY	A1
Delmarva Power & Light Company	Baa2
Duquesne Light Company	Baa2
Illinois Power Company	Ba1
Jersey Central Power & Light Company	Baa2
Metropolitan Edison Company	Baa2
New York State Electric and Gas	Baa1
NSTAR Electric Company	A1
Ohio Edison Company	Baa2
Orange and Rockland Utilities	A2
PECO Energy Company	A3
Pennsylvania Electric Company	Baa2
Pennsylvania Power Co.	Baa2
Potomac Edison Company (The)	Baa3
Potomac Electric Power Company	Baa2
PPL Electric Utilities Corporation	Baa1
Public Service Electric and Gas	Baa1
Rochester Gas & Electric Corporation	Baa1
San Diego Gas & Electric Company	A2
Texas-New Mexico Power Company	Baa3
Toledo Edison Company	Baa3
TXU Electric Delivery Company	Baa2
West Penn Power Company	Baa3
Western Massachusetts Electric Co.	Baa2

T&D Parent Companies	Senior Unsecured Rating*
AES El Salvador Trust	Baa3
CenterPoint Energy, Inc.	Ba1
CILCORP Inc.	Ba2
Consolidated Edison, Inc.	A2
Energy East Corporation	Baa2
Northeast Utilities	Baa2
NorthWestern Corporation	Ba2
NSTAR	A2
UIL Holdings Corporation	Baa3

Rising Operating Cost Structure

In general, Moody's believes that the North American regulated utility sector is facing a long-term period of rising operating costs, which include fuel and purchased power, operating and maintenance (O&M) costs, and selling, general and administrative (SG&A) expenses. The ability to recover these rising costs on a timely basis through rate relief has increasingly become a significant determinant to credit quality and highlights the importance for utility management teams to maintain constructive relationships with state regulatory authorities and provide reliable service to end-use customers.

The stable rating outlook for the sector is largely premised on our belief that these costs will be recovered on a reasonably timely basis. However, for those companies that are incurring large, multi-year deferral balances, Moody's may begin to incorporate a higher risk profile, which would create pressure to maintain a stronger balance sheet and cash flow coverage metrics. The size of these potential balances should become more clear over the next 18 to 24 months.

FUEL AND PURCHASED POWER

The largest and most volatile expense on the income statement is fuel and purchased power, which has averaged approximately 48% of revenues over the past 5 years for the integrated electric utility group. The trend has been rising, with these costs averaging 51.4% of revenues in 2006, compared with 43.7% in 2002. As noted in Table 1 below, the average gross margin for the integrated electric utilities has declined from 56% in 2002 to 49% in 2006, a decline of roughly 13%, while the gross margin of T&D utilities has remained reasonably steady.

Table 1
Gross Margin as a % Revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	56%	54%	54%	49%	49%	52%	-3.3%
T&D Utility	45%	46%	46%	45%	45%	45%	—
Utility Parent	56%	53%	51%	49%	49%	52%	-3.3%
T&D Parent	49%	48%	46%	41%	43%	45%	-3.2%

Moody's acknowledges that an assessment of gross margin is somewhat misleading for the utility sector, especially when considering the pass-through nature of many fuel and purchased power costs. For example, if a utility collects $100 in revenue and spends $50 on fuel, its gross margin would be 50%. If however, that same utility experienced a doubling of its fuel costs — to $100 — which was directly passed-on to customers, its revenues would be $150 and its gross margin would fall to 33%.

With respect to these gross margins, Moody's notes that the vast majority of utilities do not earn margins on their fuel and purchased power expenses, but instead enjoy specific rate riders to address these costs as direct pass-through items to end-use customers. Our concern with these pass-through rate riders, however, reside with the timing differences between when a company needs to procure its fuel and purchased power and when it collects the costs from ratepayers. Due to the extremely volatile nature of natural gas, oil and power commodity prices, many companies can very quickly find themselves in a significant under-recovery position, which could stress liquidity. Examples of utilities which have experienced large deferred fuel and purchased power costs include Alabama Power, Georgia Power, Virginia Electric and Power and Arizona Public Service.

Recovery of deferred fuel costs over an extended time period during which fuel costs are rising weakens the overall credit profile of utilities, due to the increasing mismatch between cost incurrence and cost recovery. Moreover, Moody's believes utilities may find themselves having a more difficult time seeking other base rate or incremental fuel relief in such an environment. End-use customers and intervener groups are also less likely to be sympathetic to the factors driving the rate increases during regulatory proceedings making the management of relationships with regulators and other interested parties challenging. (Moody's acknowledges that most large industrial customers recognize the fuel rates and the pass-through nature of the fuel riders and tend to be less concerned with this particular issue).

SELLING, GENERAL AND ADMINISTRATIVE EXPENSES

In addition to fuel costs, the fundamental operating cost structure appears to be rising as well. Industry consulting groups and data collection agencies can demonstrate a clear trend in rising costs on a per-customer basis. However, over the past 5 years, this trend can not be demonstrated through our financial analysis, as the level of SG&A expenses as a percentage of revenues appears to remain relatively stable at roughly 11% for the integrated electrics and roughly 9% for the T&D utilities.

Table 2

SG&A expenses as a % revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	11%	10%	12%	11%	10%	11%	-2.4%
T&D Utility	10%	8%	9%	9%	9%	9%	-2.6%
Utility Parent	11%	9%	10%	9%	9%	10%	-4.9%
T&D Parent	16%	10%	11%	10%	11%	12%	-8.9%

OPERATING MARGIN

However, the concern over a steadily rising operating cost structure is evident in the average operating margins. As noted in the table below, the operating margin as a percentage of revenue has steadily fallen for the integrated utilities from approximately 18% in 2002 to approximately 15% in 2006. The deterioration is also evident for the T&D utilities, which have fallen from approximately 16% in 2002 to approximately 13% in 2006.

Table 3

Operating Margin as a % revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	18%	17%	17%	15%	15%	16%	-4.5%
T&D Utility	16%	16%	16%	15%	13%	15%	-5.1%
Utility Parent	14%	15%	15%	15%	15%	15%	1.7%
T&D Parent	13%	12%	17%	11%	11%	13%	-4.1%

In general, the vast majority of the operating costs related to regulated utility operations are recoverable through base rates, and most regulatory authorities are aware of the rising costs facing the industry. While operating margin is less helpful to credit analysis, it does provide a view of profitability. Any sustained deterioration of the sector's profitability could negatively bias our sector rating outlook.

INTEREST EXPENSE

Interestingly, the average interest expense as a percentage of revenue appears to remain relatively stable at approximately 5% for the integrated electrics, having fallen from roughly 6.3% in 2002. For the T&D utilities, interest expense as a percentage of revenue fell from approximately 6.4% in 2002 to 5.75% in 2006. As debt levels and interest rates reverse the declining trend of the last several years, interest expense as a percentage of revenues may begin to increase, depending on cost of capital recovery proceedings.

Table 4

Interest Expense as a % revenue

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	6%	6%	6%	5%	5%	6%	-4.5%
T&D Utility	6%	6%	6%	5%	6%	6%	—
Utility Parent	8%	8%	8%	6%	7%	7%	-3.3%
T&D Parent	7%	7%	7%	6%	6%	7%	-3.8%

In summary, the majority of the expenses "above the line" are expected to be recovered through the regulated rate-making process, although some of this recovery could be impacted by regulatory lag. Utility companies should recover these costs and expense deferrals (such as those associated with fuel and purchased power) in a reasonably timely manner. As such, the primary credit implications associated with the costs and expenses, and recoveries associated with regulatory lag, relate to working capital and liquidity.

In general, a vast majority of utility companies maintain a relatively healthy amount of liquidity capacity that helps them mitigate the loss of financial flexibility from any delayed regulatory response to cost recoveries. We have also observed, over the past few years, a trend away from bilateral facilities and more towards committed, fully syndicated multi-year facilities without MAC clauses beyong initial closing on the facility. We view this development as a credit positive.

Larger Capital Expenditure Programs

Although industry estimates vary widely, there appears to be an expectation that the utility sector will make significant infrastructure investments over the next few years, including investments in generation, transmission and distribution assets as well as environmental mitigation. In fact, there has been a considerable increase in the projected estimates of capital expenditures in the public disclosure for year-end 2006 versus year-end 2005.

Given the relatively non-discretionary nature of the announced capital expenditure plans (such as environmental compliance, new generation build and transmission upgrades), Moody's expects a significant portion of these plans to translate into actual investments. However, we note that the timing associated with some of the announcements appears to be relatively aggressive. For example, a number of companies in the sector have announced plans to build new base load generation, such as coal or new nuclear plants. In our opinion, these projects will take approximately 50–60 months for construction, after the necessary permitting process has been completed. In addition, many T&D utilities (as well as integrated electrics) have announced new transmission projects beyond simple maintenance of the existing system. In our opinion, there will likely be significant resistance from numerous intervener groups which could potentially delay some of these projects.

There are many ways to evaluate the increase in capital expenditure plans, the most notable of which is the public disclosure in the annual SEC filings. This increasing level of investment has actually started to materialize in the financial statements as utility companies geared up over the past few years for the increases in maintenance and new projects. This increase is apparent in a ratio of capital expenditures to cash flow from operations, as noted in the table below and is arguably related to the expiration of many rate-freeze periods when capital expenditures may have been smaller.

Table 5

Capital Expenditures / CFO

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	83%	99%	78%	410%*	110%	93%	7.3%
T&D Utility	78%	72%	69%	72%	129%	84%	13.4%
Utility Parent	79%	77%	71%	113%	126%	93%	12.4%
T&D Parent	90%	55%	83%	144%	113%	97%	5.9%

** Excluded from 5-yr. average. Outlier primarily attributed to Entergy subsidiaries.*

Capital expenditure as a percentage of annual depreciation expense has also been increasing, and Moody's observes that the investments are beginning to be made in very long-lived assets with long book depreciation lives.

Table 6

Capital Expenditures / Depreciation Expense

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	286%	148%	157%	166%	200%	191%	-8.6%
T&D Utility	120%	134%	151%	172%	189%	153%	12.0%
Utility Parent	164%	147%	140%	153%	195%	160%	4.4%
T&D Parent	174%	152%	165%	165%	192%	170%	2.5%

One of the more alarming ratios that highlight the increased spending and its potential impact on credit quality is cash flow, adjusted for working capital items less dividends, as a percentage of capital expenditures. Prospectively, Moody's would expect these ratios to continue to decline over the next few years, depending on how much of the expected investment actually materializes and what recovery arrangements are in place.

Table 7

CFO Pre-W/C – Dividends / Capital Expenditures

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	101%	101%	102%	88%	76%	94%	-6.9%
T&D Utility	134%	127%	136%	95%	65%	111%	-16.6%
Utility Parent	114%	122%	123%	103%	96%	112%	-4.2%
T&D Parent	94%	104%	103%	108%	72%	96%	-6.5%

As these cash outlays begin to flow through the statement of cash flows, many companies will begin to stress their key financial credit metrics, regardless of any regulatory recovery mechanisms, due to timing differentials and the sheer size of the projects. If the expected deterioration to the financial statements materializes or if the financing plans associated with the increased expenditures primarily encompass the use of debt, negative rating actions could result. For example, SCANA Corporation and its principal utility subsidiary, South Carolina Electric and Gas, were recently placed on review for potential downgrade in part due to its announced increased spending plans driven by higher construction and material costs, new nuclear permitting costs and a change in the associated financing plans of said projects which will now be done soley with the issuance of additional debt. This is clearly a more aggressive financing policy than the company utilized previously. Otter Tail Corporation is another example of a company that has recently experienced a negative rating action (outlook changed to negative from stable) as a result of an expected deterioriation to key financial credit metrics.

Potential For Regulatory and/or Legislative Intervention

An environment of rising operating costs and capital investment needs should increase the frequency of requests for rate relief from state regulatory authorities. In Moody's opinion, these requests appear to be occurring annually or bi-annually now that many rate-freeze periods have expired. Eventually, rate-payers may resist these increases, depending on the magnitude of the increase. Additionally, individual state legislatures may feel the need to intervene to either help address the situation or revise the current rules and regulations.

Not all intervention is negative to credit quality, however. In fact, it appears that many states have recently seen regulatory or legislative intervention that has proven quite beneficial to the utility sector. In general, higher rates make future increases harder to obtain and so many utilities and regulators are beginning to pursue a series of smaller annual increases in an effort to avoid a more dramatic rate shock.

States with More Constructive Recent Regulatory or Legislative Actions	States with Less Constructive Recent Regulatory or Legislative Actions
Wisconsin	Maryland
Virginia	Illinois
Iowa	Arkansas
Florida	Arizona
Louisiana	
Nevada	
North Carolina	
South Carolina	

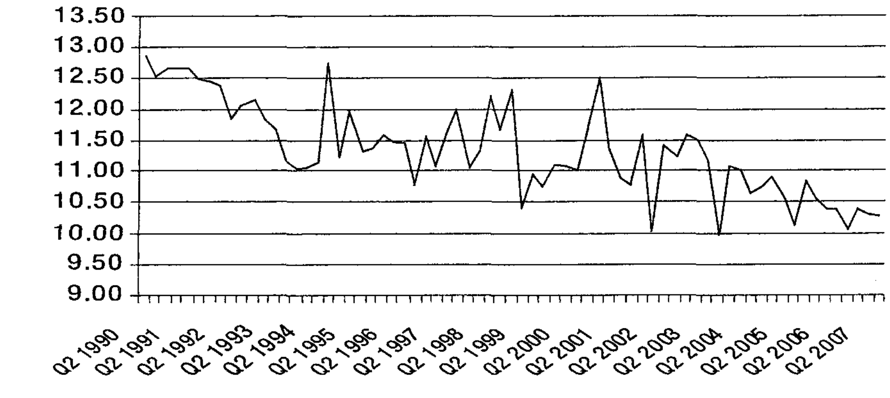
From a credit perspective, the intervention risk could also be affected by management's desire to attain pre-approvals on investments or other cash recovery mechanisms or assurances prior to committing to a particular investment. A future regulatory risk could arise over the intermediate- to longer-term where regulatory authorities find it beneficial to allow for pre-approval or other assurances for recovery but subsequently prescribe a lower allowed equity return reflecting the lower risk profile of the investment.

Table 8

Net Income / Average Equity

	2002	2003	2004	2005	2006	4-yr Avg	3-yr CAGR
Integrated Utility	n/a	11%	11%	10%	10%	11%	-3.1%
T&D Utility	n/a	13%	12%	11%	9%	11%	-11.4%
Utility Parent	n/a	10%	9%	10%	11%	10%	-3.2%
T&D Parent	n/a	12%	11%	9%	12%	11%	—

The chart below is a graphical depiction of average awarded ROE's as calculated by the Edison Electric Institute which shows a similar trend to our analysis in Table 8.



Source: EEI Q2 2007 Financial Update.

Given current macroeconomic market conditions, Moody's believes there are several regulatory commissions that are actively targeting progressively lower equity returns, presumably on the premise that utilities are lower-risk businesses than industrial companies. Consequently, the equity market valuations being ascribed to the regulated utility sector, which are at all-time highs, are likely to reverse themselves in the future. This potential outcome might lead many regulators to question why more companies did not look to access relatively cheap equity at this time, knowing they were entering a phase of significant infrastructure investment.

Moody's believes there is a discernable difference between individual state regulatory commissions, their relationship with the utilities they regulate and individual states' prior attempts to deregulate the industry. As noted in the charts below, the states in the southeastern region of the United States and in the West / Southwest, have produced, on average over the past 5 years, higher credit metrics than the states in the Northeast / Mid-Atlantic region, where most utilities divested their generation assets, or perhaps transferred those assets into a less-regulated, affiliate entity. Interestingly, in addition, it appears as if the average metrics for the utilities in the West/Southwest peer group may be experiencing some lift from California.

Chart A

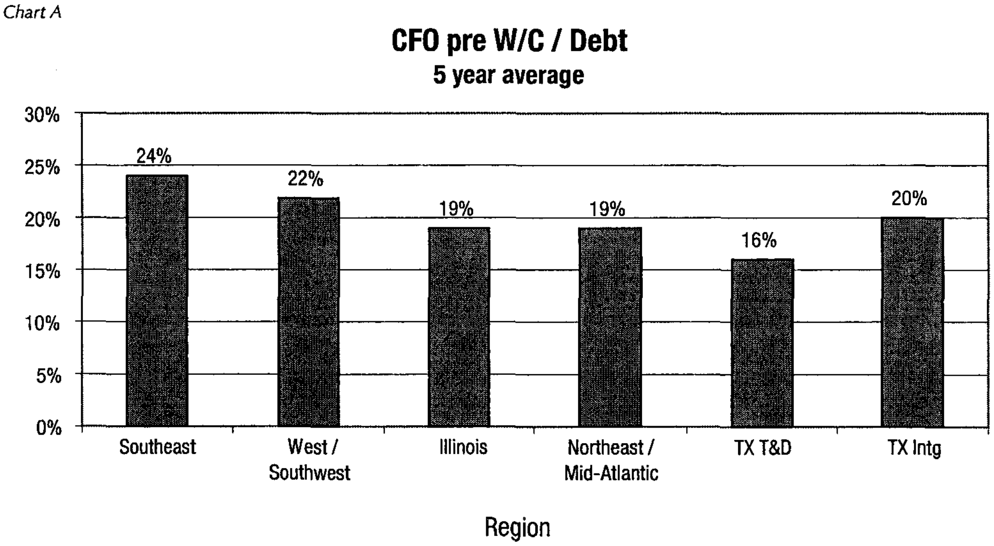
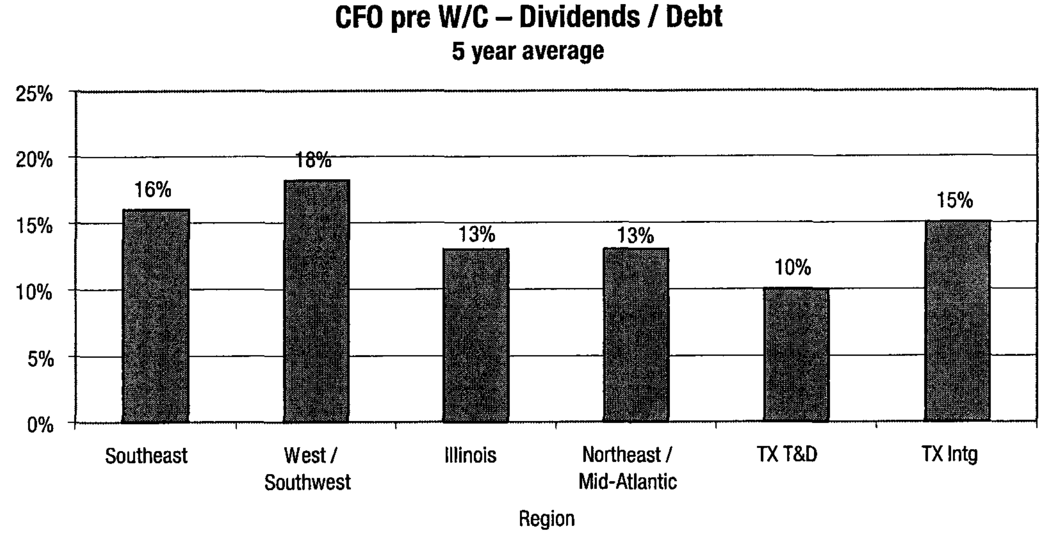
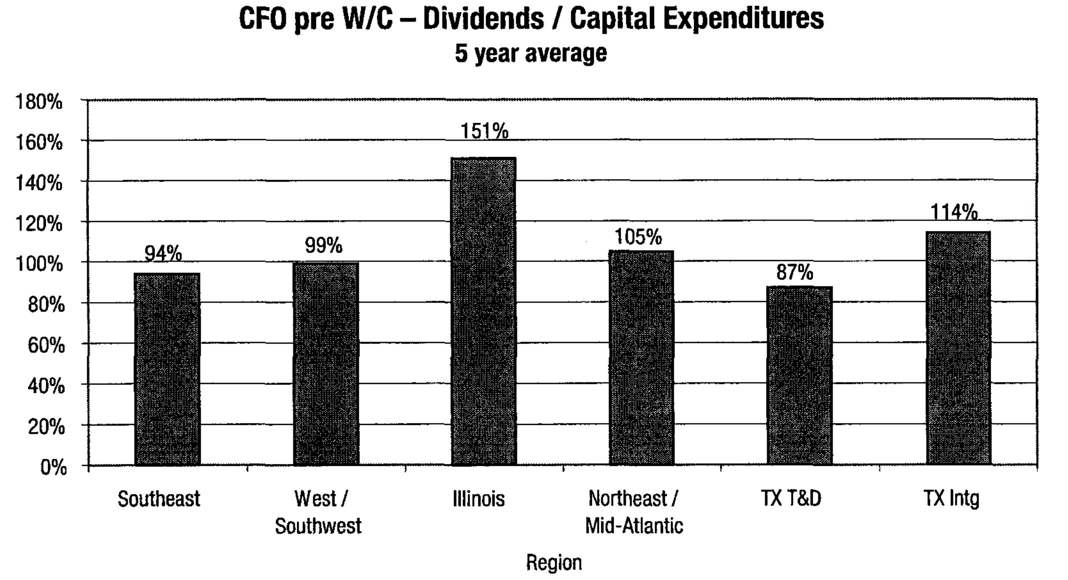


Chart B



As demonstrated in these charts, the T&D-related utilities in Illinois and the Northeast / Mid-Atlantic region tend to produce a lower level of cash flow to adjusted total debt than their integrated peers, given their rating category. Theoretically, this makes sense given the lower business and operating risk profile associated with many of these T&D utilities, as they generally do not have the more risky generation assets within the vertically integrated utility structure. However, many of these utilities need to procure their power supplies on the open market or through bi-lateral agreements with power generators or merchant energy companies. While these costs are generally passed through to end-use consumers through various rate-rider mechanisms, there could be very significant and potentially devastating consequences to credit quality if regulators, legislators, or other political leaders intervene over rapidly rising prices. This case is most prominent in Illinois where the legislators, not the regulators, lead the intervention, in part due to the steep increase in rates that went into effect this past January after a 10-year rate freeze.

Chart C



Generous Shareholder Rewards Policies Appear Inconsistent With Increasing Business and Operating Risk Profiles

In general, Moody's observes that most companies and industries that are facing increasing business and operating risk profiles tend to institute corporate finance strategies that are designed to bolster the balance sheet in an effort to address rising uncertainties in a more conservative manner. In the regulated utility sector, some companies appear to be more focused on competing for investor attention by instituting overly generous shareholder reward policies. These shareholder reward polices typically include steady and predictable annual dividend rate increases and equity repurchase programs.

Over the past few years, Moody's has observed a trend where many utility companies are beginning to slowly increase both their leverage and dividend obligations or reinstitute the payment of dividends, such as CMS Energy (dividend only) or Dominion Resources. Moody's generally considers dividends as a fixed expense given the historical reluctance of issuers to either cut or halt the dividends except when confronted with an extremely dire financial situation. Several companies have also raised their dividend payout targets in an effort to attract or retain investor interest. While Moody's recognizes the importance of issuers maintaining strong equity interest given the capital intensive nature of the industry and the need to tap the equity markets from time-to-time to help maintain their metrics, Moody's would also prefer to see a more consistent balance between protection of creditors and shareholder rewards in an effort to defend a particular rating. In the table below, Moody's observes that the average dividend payout for the sector has declined for the integrated utilities and increased for the T&D parent companies.

Table 9
Dividend Payout Ratio (Dividends / Net Income)

	2002	2003	2004	2005	2006	4-yr Avg	3-yr CAGR
Integrated Utility	n/a	82%	75%	44%	68%	67%	-6.0%
T&D Utility	n/a	139%	77%	89%	134%	110%	-1.2%
Utility Parent	n/a	69%	74%	44%	56%	61%	-6.7%
T&D Parent	n/a	69%	69%	139%	106%	96%	15.2%

A majority of the integrated electric utilities in our coverage universe are subsidiaries of parent holding companies. As such, many of the utilities incorporate financial policies that are designed to achieve a leverage target consistent with the allowed regulated equity ratio or regulated capital structure. As a result, some of these subsidiaries are actually demonstrating a reasonably consistent retained cash flow to debt ratio. The same can not be said for the T&D utilities, which have had steadily declining retained cash flow to debt ratios since 2004.

Table 10
CFO pre W/C – Dividends / Debt

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Integrated Utility	16%	17%	17%	15%	17%	16%	2.0%
T&D Utility	13%	13%	16%	14%	10%	13%	-8.3%
Utility Parent	12%	14%	14%	13%	14%	13%	5.2%
T&D Parent	9%	10%	11%	12%	9%	10%	—

From a credit perspective, these shareholder reward programs could have implications in companies' dealings with regulators or legislators. Regulatory authorities may feel less sympathetic to companies that might find themselves in increasingly stressful financial conditions as they recall the equity repurchases or other shareholder rewards of the past few years. Under this scenario, it is conceivable that regulators may ask management why it would implement these programs in the face of increasing business and operating risks; especially as it relates to building new base-load generation facilities. This leads us back to the issues of constructive regulatory relationships and timely recovery of costs.

Comparison to Other Regulated, Capital Intensive Industries

Moody's compared the integrated electric utilities and T&D utilities to a selected group of peer industries. These peers are large, capital-intensive industries that are also affected by significant amounts of regulation — for example, environmental or safety-related regulation — or are affected by commodity cycles or weather. For each comparable sector, we selected a small group of companies that we believe constitute a reasonable representation for the peer group average. A list of the companies selected for the peer group is included in Appendix A.

Table 11

CFO pre W/C + Interest / Interest

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Steel	9.2x	6.6x	19.9x	18.0x	22.3x	15.2x	24.8%
Major Oil	8.0x	13.5x	15.1x	18.0x	18.6x	14.6x	23.5%
Shipping	6.3x	7.3x	8.4x	8.3x	7.9x	7.7x	5.8%
Chemicals	5.3x	7.0x	7.5x	7.7x	7.6x	7.0x	9.4%
Integrated Utility	4.9x	5.1x	5.4x	5.0x	4.9x	5.1x	0
Divr. Nat. Gas	4.5x	4.9x	4.9x	4.0x	5.7x	4.8x	6.1%
Paper	3.5x	4.4x	4.6x	4.6x	5.5x	4.5x	12.0%
Railroads	3.8x	4.0x	4.3x	4.7x	5.5x	4.5x	9.7%
T&D Utility	4.1x	4.1x	5.0x	5.0x	3.7x	4.4x	-2.5%
Utility Parent	3.5x	3.7x	3.9x	3.8x	4.0x	3.8x	3.4%
Airlines	3.2x	4.1x	3.5x	3.2x	4.0x	3.6x	5.7%
T&D Parent	2.9x	3.2x	3.3x	3.4x	3.1x	3.2x	1.7%

Table 12

CFO pre W/C / Debt

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Major Oil	34%	58%	70%	95%	98%	71%	30.3%
Steel	31%	20%	92%	83%	120%	69%	40.3%
Chemicals	25%	27%	34%	39%	42%	33%	13.9%
Shipping	22%	29%	34%	37%	35%	31%	12.3%
Paper	15%	22%	22%	23%	31%	23%	19.9%
Integrated Utility	24%	25%	25%	21%	22%	23%	-2.2%
Divr. Nat. Gas	19%	21%	22%	18%	29%	22%	11.2%
T&D Utility	20%	19%	23%	21%	16%	20%	-5.4%
Railroads	17%	18%	20%	23%	28%	21%	13.3%
Utility Parent	16%	18%	18%	18%	19%	18%	4.4%
T&D Parent	12%	13%	15%	16%	15%	14%	5.7%
Airlines	10%	13%	11%	11%	18%	13%	15.8%

One of the more interesting differentiation factors between these large capital intensive industrial sector peers and the utility industry is the ability of the industrials to capitalize on commodity prices. This is most evident with the major oil and steel companies. Oil companies, in general, do not hedge their production the way utilities hedge, and as a result the significant rise in oil prices has resulted in a dramatic impact on earnings and cash flows. Similarly, steel companies have benefited from increased demand and higher prices.

Table 13
CFO pre W/C – Dividends / Debt

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Steel	25%	17%	87%	73%	96%	60%	40.0%
Major Oil	25%	46%	57%	76%	82%	57%	34.6%
Shipping	19%	25%	30%	32%	31%	27%	13.0%
Chemicals	19%	22%	27%	31%	32%	26%	13.9%
Railroads	16%	17%	18%	21%	25%	19%	11.8%
Paper	11%	17%	18%	18%	25%	18%	22.8%
Divr. Nat. Gas	14%	17%	18%	13%	24%	17%	14.4%
Integrated Utility	16%	17%	17%	15%	17%	16%	1.5%
T&D Utility	13%	13%	16%	14%	10%	13%	-6.4%
Airlines	10%	13%	11%	11%	18%	13%	15.8%
Utility Parent	12%	14%	14%	13%	14%	13%	3.9%
T&D Parent	9%	10%	11%	12%	9%	10%	—

Moody's also observes that there is a noticeable consistency among the regulated industries with respect to annual credit ratios versus the more volatile industrial sectors. That being said, Moody's also notes that the industrial peers, many of whom are bailing hay while the sun shines, are not overly leveraging their balance sheets when times are good. Theoretically, this may be due to the inherent acknowledgement that the cyclical nature of the industry sector may eventually turn around again, and some industrial companies are less enthusiastic to an increased level of leverage if they believe future cash flows may be stressed.

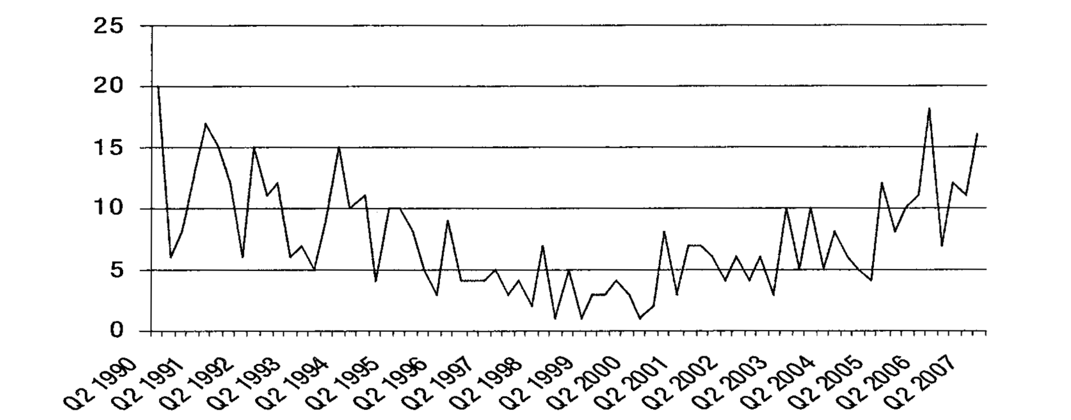
Table 14
CFO pre W/C – Dividends / Capital Expenditures

	2002	2003	2004	2005	2006	5-yr Avg	4-yr CAGR
Steel	191%	62%	419%	333%	365%	274%	17.6%
Chemicals	148%	217%	224%	216%	168%	195%	3.2%
Paper	135%	215%	213%	173%	220%	191%	13.0%
Shipping	109%	154%	212%	242%	173%	178%	12.2%
Major Oil	96%	146%	157%	175%	163%	147%	14.2%
Railroads	121%	117%	120%	127%	137%	124%	3.2%
Utility Parent	114%	122%	123%	103%	96%	112%	-4.2%
T&D Utility	134%	127%	136%	95%	65%	111%	-16.6%
T&D Parent	94%	104%	103%	108%	72%	96%	-6.8%
Integrated Utility	101%	101%	102%	88%	76%	94%	-6.9%
Divr. Nat. Gas	69%	113%	113%	63%	91%	90%	7.2%
Airlines	56%	76%	72%	84%	105%	79%	17.0%

Conclusion

The regulated electric utility sector is currently facing a period of rising expenses, huge needs to invest in its infrastructure and significant needs to address steadily increasing environmental mandates. As a result, the sector will most likely be very active with state regulators in seeking rate relief, which could strain the reasonably constructive relationships they have enjoyed over the last few years. In addition, legislators may view the sector as an easy target with which to score political points, and may intervene to protest the steadily rising costs associated with lighting, heating and cooling constituent's homes or businesses.

The chart below depicts the number of rate cases filed by utilities as calculated by the Edison Electric Institute.



Source: EEI 2Q 2007 Financial Update

However, none of the issues currently facing the industry are new. In fact, the utility sector has faced an environment with eerily similar uncertainties in the past. The risk, in our opinion, is whether or not the experiences of the past will be repeated in the future. The most significant risk might be future disallowances of investments that were made with an understanding that those investments were prudent and necessary at the time they were made.

Our concern is that even in states with reasonably constructive CWIP or other construction recovery mechanisms, over the life of construction, only approximately 10% – 20% of the total project costs would be recovered. If the balance of the costs, in this case 80% – 90%, were added to rate base in year 5 or 6, rate shock could be meaningful for some utilities. If this scenario materializes, Moody's would be concerned if the regulatory relationship is more confrontational, potentially increasing the risk for large deferrals or disallowances, as had been sometimes the case in previous years. In addition, while Moody's did not spend any material attention to the risks associated with carbon legislation or carbon tax issues in this report, we believe the issues over carbon could be substantial for utility companies over the next several years.

From a credit perspective, it is unclear what impact these storm clouds on the horizon may have on the utility sector. The risks that are currently being highlighted are sufficiently far enough out on the horizon that there appears to be little threat of imminent rating action especially if key financial credit ratios remain at current levels. However, Moody's has raised a question on many occasions as to whether or not utility companies should be re-doubling their efforts to strengthen balance sheets and bolster liquidity capacity, given the potential risks over the intermediate and longer-term horizons.

From a rating perspective, Moody's expects to carefully monitor utility investment plans, the associated financing plans related to those investments and the potential those investments could have on future rate cases. While we recognize that there are significant needs that need to be addressed — in terms of generation capacity, fuel diversity, transmission and distribution upgrades and enhancements and substantial uncertainties associated with increasingly stringent environmental mandates — credit quality could suffer if key financial ratios were to deteriorate meaningfully or if the deterioration appeared to be sustained for an extended period of time.

Déjà vu All Over Again

The following excerpts are from an annual report published by a large, multi-state utility holding company. Can you guess what year the report was published?

A. 2005
B. 1996
C. 1970
D. 1964

"...inflationary pressures pushed the costs of doing business progressively higher and compelled ...our operating companies to ask for rate increases."

"... difficulties as fuel shortages and environmental concerns..."

"...operating expenses reached new heights, primarily because of significant increases on the costs of fuel and of purchased power....Labor and materials costs, too, were higher than ever before."

"Construction of generation plants and other needed facilities continues to carry high priority in the...planning for the future, as do research and development activities aimed at finding ways to protect more effectively the quality of air and water in our service area."

"...subnormal hydroelectric generating conditions."

"Contributing to...higher construction costs are the environment-protection facilities associated with the production of electric power."

"Public concern over fuel shortages, power supply inadequacies, need for increased revenues, and ecological considerations — more visible than usual through increased national news coverage — amplified the concern already being shown by the nation's producers of electric power."

"...it is probable that about half of the new generation installed...on the system...will be nuclear."

"In the long run, the development of "clean coal" — through gasification or solvent refining — probably will provide the most feasible solution to the challenging problem of controlling stack effluents."

Answer: C. 1970 The Southern Company

Related Research

Special Comments:

Moody's Comments on the Credit Implications Associated with North American Utility Consolidation, December 2006 (# 101392)

Moody's Comments on the Back to Basics Strategy for the North American Electric Utility Sector, November 2006 (# 100660)

Criteria for Assessing Director Independence, October 2006 (# 100302)

Covenants and Ring-Fencing for Wholly-Owned Subsidiaries, May 2007 (# 102983)

Environmental Regulations Increase Capital Costs for Public Power Electric Utilities, June 2007 (# 103616)

Regulation Of Greenhouse Gases: Substantial Credit Challenges Likely Ahead For U.S. Public Power Electric Utilities, June 2007 (# 103356)

Rating Methodologies:

Global Regulated Electric Utilities, March 2005 (# 91730)

Global Integrated Oil & Gas, October 2005 (# 94696)

Global Steel Industry, October 2005 (# 94683)

Global Paper & Forest Products Industry, June 2006 (# 95092)

Global Chemicals and Allied Products, February 2002 (# 74324)

North American Diversified Natural Gas Transmission And Distribution Companies, March 2007 (# 102513)

Industry Outlook:

U.S. Electric Utilities, December 2006 (# 101304)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix A

Company	Senior Unsecured Rating
Airlines	
Southwest Airlines	Baa1
AMR Corporation	B2
Continental Airlines	B2
JetBlue Airways	B2
Major Oils	
Exxon Mobil Corporation	Aaa
BP plc	Aa1
Royal Dutch Shell plc	Aa1
Chevron Corporation	Aa2
Conoco Phillips	A1
Marathon Oil	Baa1
Diversified Natural Gas	
Equitable Resources	A2
KeySpan Corporation	A3
Consolidated Natural Gas	Baa1
National Fuel Gas	Baa1
CenterPoint Energy Resources Corp	Baa3
Southern Union	Baa3
Williams Companies	Ba2
El Paso Corp	Ba3
Questar	—
Paper	
Sonoco Products Company	Baa1
Weyehaeuser Company	Baa2
International Paper	Baa3
Temple-Inland	Baa3
Railroads	
Burlington Northern Santa Fe	Baa1
Norfolk Southern Corp	Baa1
CSX Corporation	Baa2
Union Pacific Corp	Baa2
Shipping	
United Parcel Service	Aaa
FedEx Corp	Baa2
Con-way Incorporated	Baa3
Overseas Shipping Corp	Ba1
Chemicals	
E.I. DuPont de Nemours & Company	A2
Praxair, Inc.	A2
Dow Chemical Company	A3
Monsanto Company	Baa1
Steel	
Nucor Corporation	A1
United States Steel	Baa3
Steel Dynamics	Ba1
AK Steel Holdings Corp	B1

Southeast	West/Southwest	Illinois	Northeast/Mid-Atlantic	TX T&D	TX Integrated
Alabama Power	Arizona P.S.	Ameren CIPS	Baltimore G&E	AEP Central	El Paso Electric
Appalachian Power	Nevada Power	Commonwealth Ed	Boston Ed	AEP North	ETR- Gulf States
Cleco Power	P.S. Colorado	Illinois Power	Central Hudson	CEHE	SPS
Duke Carolinas	P.S. New Mexico	PECO	Central Main Power	TNMP	SWEPCo
ETR - LA	PG&E		Con. Ed	TXU Delivery	
ETR - MS	San Diego G&E		Connecticut L&P		
FP&L	Sierra Pacific Power		Delmarva P&L		
Georgia Power	SoCal Edison		JCP&L		
Gulf Power	Tucson Electric		Mass. Electric		
Kentucky Power			Met. Ed		
Kentucky Utilities			NYSEG		
Louisville G&E			Penn. Electric		
Mississippi Power			Potomac Electric		
Monongahela Power			PPL Electric		
PGN - Carolina			PSE&G		
PGN - Florida			Rochester G&E		
Savannah Electric					
Virginia Electric					
Tampa Electric					
South Carolina E&G					

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Author	Associate Analysts	Production Specialist
James Hempstead	*Indu Sambandam, CFA* *Ryan Wobbrock*	*Ida Chan*

UNS ELECTRIC, INC.'S RESPONSES TO
RUCO'S FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
March 26, 2007

1.09 Depreciation – Please provide the following information regarding depreciation:

a) Convention, e.g., full-year, half year, other (specify); and

b) The composite or individual plant account depreciation rates applied to calculate the depreciation expense since the last rate case and reference the authority for such rates i.e. Decision No.

RESPONSE:

a) The Company uses a mid-month convention with one-half month depreciation accrued on assets in the month of their addition to Plant in Service and also one-half month depreciation in the month when they are retired from service.

b) The current book depreciation rates being used are the same as those that were being used by Citizens when the assets were acquired in August, 2003. Please see Bates No. UNSE(0783)00407 for a summary. The most recent depreciation rate authority was that contained in Decision No. 58360 issued on July 23, 1993.

RESPONDENT: Carl Dabelstein

WITNESS: Karen Kissinger

EXHIBIT
UNSE 37
Admitted

F.E.R.C.	Depreciation Rate	
Acct. No.	Mohave	Santa Cruz
302	-	-
303 -		
Software	20.00	20.00
WAPA Comm. Line (a)	4.13	-
WAPA Switchyard (b)	2.92	
311	2.50	2.50
316	-	2.88
340	-	-
341	-	1.38
342	-	2.42
343	-	2.34
344	-	0.67
345	-	2.20
346	-	1.87
350	-	-
352	3.77	3.77
353	2.92	2.92
354	2.87	4.32
355	5.77	5.77
356	2.71	2.71
358	4.36	-
359	2.01	2.01
360	-	-
361	3.20	3.20
362	4.82	4.82
364	4.23	4.23
365	4.36	4.36
366	4.28	4.28
367	5.36	5.36
368	4.93	4.93
369	4.23	4.23
370	3.25	3.25
373	4.55	4.55
389	-	-
390	2.89	2.89
391 -		
Office Furniture & Equip.	3.72	3.72
Computer Equipment	20.00	20.00
392 -		
Vehicles < $100K	25.00	25.00
Vehicles > $100K	12.50	12.50
393	2.62	2.62
394	3.02	3.02
395	2.41	2.41
396	3.33	3.33
397	4.13	4.13
398	5.45	5.45

(a) WAPA Fiber Optic Communictions Line - Depreciated at same rate as Acct.No. 397, Communications Equipment.
(b) WAPA Switchyard - Depreciated at same rate as Acct. 353, Station Equipment.

Vehicle Depreciation
UNSE Electric as Compared with RUCO

Line No.	Period	Beginning Balance	Ending Balance	Average Balance	Depr. Rate (%)	Depr. Provision	Accum. Depr. per UNSE	Accum. Depr. per RUCO
1	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2	August 11, 2003 - December 31, 2003:							
3	UNSE Computation -							
4	Class 1 Vehicles	387,742	387,742	387,742	25.00	37,708		
5	Class 2 Vehicles	728,561	728,561	728,561	25.00	70,853		
6	Class 3 Vehicles	1,479,188	1,479,188	1,479,188	25.00	143,851		
7	Class 4 Vehicles	4,829,984	4,829,984	4,829,984	12.50	234,858		
8	Class 5 Vehicles	-	-	-	12.50	-		
9		7,425,475	7,425,475	7,425,475		487,269	487,269	
10	RUCO Computation -	7,425,475	7,425,475	7,425,475	25.00	722,204 (1)		722,204
11								
12	Calendar Year 2004:							
13	UNSE Computation -							
14	Class 1 Vehicles	387,742	417,693	402,718	25.00	100,679		
15	Class 2 Vehicles	728,561	728,561	728,561	25.00	182,140		
16	Class 3 Vehicles	1,479,188	1,590,235	1,534,712	25.00	383,678		
17	Class 4 Vehicles	4,829,984	4,829,984	4,829,984	12.50	603,748		
18	Class 5 Vehicles	-	-	-	12.50	-		
19		7,425,475	7,566,473	7,495,974		1,270,246	1,757,515	
20	RUCO Computation	7,425,475	7,566,473	7,495,974	25.00	1,873,994 (1)		2,596,198
21								
22	Calendar Year 2005:							
23	UNSE Computation -							
24	Class 1 Vehicles	417,693	366,331	392,012	25.00	98,003		
25	Class 2 Vehicles	728,561	882,289	805,425	25.00	201,356		
26	Class 3 Vehicles	1,590,235	1,007,316	1,298,776	25.00	324,694		
27	Class 4 Vehicles	4,829,984	4,808,218	4,819,101	12.50	602,388		
28	Class 5 Vehicles	-	584,467	292,234	12.50	36,529		
29		7,566,473	7,648,621	7,607,547		1,262,970	3,020,484	
30	RUCO Computation	7,566,473	7,648,621	7,607,547	25.00	1,901,887 (1)		4,498,084
31								
32	January 1, 2006 - June 30, 2006							
33	UNSE Computation -							
34	Class 1 Vehicles	366,331	366,331	366,331	25.00	45,791		
35	Class 2 Vehicles	882,289	1,151,600	1,016,945	25.00	127,118		
36	Class 3 Vehicles	1,007,316	1,185,238	1,096,277	25.00	137,035		
37	Class 4 Vehicles	4,808,218	5,641,611	5,224,915	12.50	326,557		
38	Class 5 Vehicles	584,467	1,995,626	1,290,047	12.50	80,628		
39		7,648,621	10,340,406	8,994,514		717,129	3,737,614	
40	RUCO Computation	7,648,621	10,340,406	8,994,514	25.00	1,115,073 (1)		5,613,157
41								
42	Excess depreciation computed by RUCO through use of incorrect rate for Class 4 and Class 5 vehicles.							1,875,544
43								

(1) Agrees with RLM-5, Pages 3 of 6 through 6 of 6

EXHIBIT
tabbies
UNSE 38
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-17: With regards to RUCO's Operating Income Adjustment No. 5 – as described in Mr. Moore's Direct Testimony at page 17 – please describe if and how Mr. Moore disagrees with any of the following statements:

a. Unlike other utilities providing service in the state, UNS Electric does not have internal personnel and support services built into its base rates.

b. TEP employees who perform services for UNS Electric directly record those costs to UNS Electric, as opposed to using the Massachusetts Formula to allocate such services.

c. That RUCO based its rate case expense recommendation for UNS Gas in Docket No. G-04204A-06-0463 on what was granted as rate case expense for Southwest Gas Corporation in Decision No. 68487 (February 23, 2006).

d. That Southwest Gas Corporation's system-allocated labor costs were 6.38 percent of operating expenses.

e. That Southwest Gas Corporation has internal personnel and support services built into its base rates.

Response: Rodney L. Moore

a. – e. I agree with statement.

EXHIBIT
tabbies
UNSE 39
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-18: Do Mr. Moore and RUCO recommend that UNS Electric use the Massachusetts Formula to allocate services TEP employees perform for UNS Electric? If not, please explain why not, in light of RUCO's reliance on Decision No. 68487 for its disallowance of UNS Electric's rate case expense.

Response: Rodney L. Moore

No. To avoid burdening other affiliates with UNS Electric rate case expenses TEP employees who perform services for UNS Electric directly should record those costs to UNS Electric.

EXHIBIT
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UNSE 40
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-30: Does Mr. Moore disagree that the group of employees that receive PEP provide services to customers of UNS Electric? If he disagrees, provide and all support that forms the basis for Mr. Moore's belief.

Response: Rodney L. Moore

I agree that only 29.5 full-time equivalent employees or 16.62 percent of the Company's workforce comprise the group of employees that are eligible to receive PEP; and this small group of employees provide services to customers of UNS Electric.

EXHIBIT
tabbies
UNSE 41
Admitted

From: Al Amezcua [Aamezcua@azcc.gov]
Sent: Wednesday, May 23, 2007 1:53 PM
To: Rodney Moore
Cc: Connie Walczak; Vicki Wallace; dcouture@tep.com; Al Amezcua
Subject: Query: UNS Electric consumer complaint

Rodney,

The following is the information you requested regarding the total number of complaints received by Consumer Services for Quality of Service issues.

1/1/04 - 12/31/04 Complaints

Quality of Service: 17

Total 111

1/1/05 - 12/31/05

Quality of Service: 31

Total 121

1/1/06 - 12/31/06

Quality of Service: 44

Total 130

1/1/07 - 5/21/07

Quality of Service: 04

Total 26

The following is a category breakdown for the Electric Quality of Service Code:

(5) Quality of Service
5A - Response Time
5B - Misinformation
5C - Customer Service Contact
5D - Field or Premises Visit
5E - Outage or Interruptions
5F - Can't Reach Company
5G - Pressure or Voltage
5Z - Other

EXHIBIT
UNSE.42
Admitted

The following numbers reflect ELECTRIC only complaints:

2004 - 17 "quality of service" complaints out of a total of 111 filed, or 15.3%.

2005 - 31 "quality of service" complaints out of a total of 121, or 25.6%.

2006 - 44 "quality of service" complaints out of a total of 130, or 33.8%.

2007 - 04 "quality of service" complaints out of a total of 26, or 15.3%.

Dave Couture was provided this information.

Thank you,

Al Amezcua
Public Utilities Consumer Analyst II
Arizona Corporation Commission
Utilities Division
(602) 542-0842

UNSE EXHIBIT

Summaries of Estimated Average Retail Rate Impacts

For Period June 2008 – May 2009

EXHIBIT
UNSE-43
Admitted

UNS Electric, Inc.
Base Rates and Impact of Market Based
Purchased Power and Fuel Cost (Permian Gas @ $7.50 / mmBtu)

			Base Rates and Estimated PPFAC June 2008 through May 2009		
Average Rate - ¢/kWh	Present Rates	Proposed Rates under PWCC Contract	Before Rate Reclassification	Adjustment for BMGS	After Rate Reclassification
Base Rate - Delivery Charges	2.83	3.36	3.36	0.62	3.98
Base Rate - Fuel & Purchased Power	5.19	7.04	7.04	(0.62)	6.42
PPFAC - Existing Rate	1.83	-	-	-	-
PPFAC - Forward Component	-	-	1.73	-	1.73
PPFAC - True-Up Component (1)	-	-	(0.16)	-	(0.16)
Total	9.85	10.40	11.97	-	11.97
Percentage Increase from Present		5.6%	21.5%		21.5%

Notes
(1) True-up component based on forecasted PPFAC balance of ($2.9) million as of June 2008.

UNS Electric, Inc.
Base Rates and Impact of Market Based
Purchased Power and Fuel Cost

Average Rate - ¢/kWh	Present Rates	Proposed Rates under PWCC Contract	Base Rates and Estimated PPFAC with Black Mountain Generating Station (June 2008 through May 2009)		
			Permian Gas at $6.00	Permian Gas at $7.50	Permian Gas at $9.00
Base Rate - Delivery Charges (1)	2.83	3.36	3.98	3.98	3.98
Base Rate - Fuel & Purchased Power (1)	5.19	7.04	6.42	6.42	6.42
PPFAC - Existing Rate	1.83	-	-	-	-
PPFAC - Forward Component	-	-	0.48	1.73	2.98
PPFAC - True-Up Component	-	-	(0.16)	(0.16)	(0.16)
Total	9.85	10.40	10.72	11.97	13.22
Percentage Increase from Present		5.6%	8.8%	21.5%	34.2%

Average Rate - ¢/kWh	Present Rates	Proposed Rates under PWCC Contract	Base Rates and Estimated PPFAC with BMGS and Solid Fuel Resource (June 2008 through May 2009)		
			Permian Gas at $6.00	Permian Gas at $7.50	Permian Gas at $9.00
Base Rate - Delivery Charges (1)	2.83	3.36	3.98	3.98	3.98
Base Rate - Fuel & Purchased Power (1)	5.19	7.04	6.42	6.42	6.42
PPFAC - Existing Rate	1.83	-	-	-	-
PPFAC - Forward Component (2)	-	-	0.37	0.90	1.39
PPFAC - True-Up Component	-	-	(0.16)	(0.16)	(0.16)
Total	9.85	10.40	10.61	11.14	11.63
Percentage Increase from Present		5.6%	7.7%	13.1%	18.1%

Notes
(1) Estimated rates reflects proposed rate reclassification for BMGS.
(2) Assumes 168MW solid fuel resource delivered to UNSE beginning June 2008.

EXHIBIT
UNSE-44
Admitted

UNSE EXHIBIT

Estimated Rates with BMGS and Permian Gas @ $7.50

For Period June 2008 – May 2009

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station (Permian Gas @ $7.50/mmBtu)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC	Total Estimated Increase %
Residential Service Delivery Charges - Mohave County				
Customer Charge	$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs	$0.07490	$0.013056	$0.019693	
Energy Charge, all additional kWhs	$0.07490	$0.023056	$0.029693	
Residential Service Base Power Supply Charge, all kWhs		$0.073771	$0.067245	
PPFAC Charge	$0.01825	$0.000000	$0.015699	
Average Sales per Month				
0	$6.50	$7.70	$7.70	18.46%
50	$11.16	$12.04	$12.83	15.01%
100	$15.82	$16.38	$17.96	13.59%
200	$25.13	$25.07	$28.23	12.32%
400	$43.76	$42.43	$48.75	11.41%
600	$62.39	$61.80	$71.28	14.25%
800	$81.02	$81.16	$93.81	15.78%
1,000	$99.65	$100.53	$116.34	16.74%
2,000	$192.80	$197.35	$228.97	18.76%
2,500	$239.38	$245.77	$285.29	19.18%
5,000	$472.25	$487.84	$566.88	20.04%
10,000	$938.00	$971.97	$1,130.06	20.48%

Residential Service Delivery Charges - Santa Cruz County				
Customer Charge	$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs	$0.079300	$0.013056	$0.019693	
Energy Charge, all additional kWhs	$0.079300	$0.023056	$0.029693	
Residential Service Base Power Supply Charge, all kWhs		$0.073771	$0.067245	
PPFAC Charge	$0.018250	$0.000000	$0.015699	
Average Sales per Month				
0	$6.50	$7.70	$7.70	18.46%
50	$11.38	$12.04	$12.83	12.78%
100	$16.26	$16.38	$17.96	10.51%
200	$26.01	$25.07	$28.23	8.52%
400	$45.52	$42.43	$48.75	7.11%
600	$65.03	$61.80	$71.28	9.61%
800	$84.54	$81.16	$93.81	10.96%
1,000	$104.05	$100.53	$116.34	11.81%
2,000	$201.60	$197.35	$228.97	13.58%
2,500	$250.38	$245.77	$285.29	13.95%
5,000	$494.25	$487.84	$566.88	14.70%
10,000	$982.00	$971.97	$1,130.06	15.08%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station (Permian Gas @ $7.50/mmBtu)

		Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC	Total Estimated Increase %
Residential Service Cares - Delivery Charges Mohave County					
Customer Charge		$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs		$0.074900	$0.013056	$0.019693	
Energy Charge, all additional kWhs		$0.074900	$0.023056	$0.029693	
Residential Service Cares Base Power Supply Charge, all kWhs			$0.073771	$0.067245	
PPFAC Charge		$0.018250	$0.000000	$0.015699	
Discount		Varies	$8.00	$8.00	
Average Sales per Month					
0	30%	$6.50	$7.70	$7.70	18.46%
50	30%	$7.81	$7.70	$7.70	-1.41%
100	30%	$11.07	$8.38	$9.96	-10.00%
200	30%	$17.59	$17.07	$20.23	14.99%
400	20%	$35.01	$34.43	$40.75	16.41%
600	20%	$49.91	$53.80	$63.28	26.79%
800	10%	$72.92	$73.16	$85.81	17.68%
1,000	10%	$89.69	$92.53	$108.34	20.80%
2,000	$8.00	$184.80	$189.35	$220.97	19.57%
2,500	$8.00	$231.38	$237.77	$277.29	19.84%
5,000	$8.00	$464.25	$479.84	$558.88	20.38%
10,000	$8.00	$930.00	$963.97	$1,122.06	20.65%
Residential Service Cares - Delivery Charges Santa Cruz County					
Customer Charge		$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs		$0.079300	$0.013056	$0.019693	
Energy Charge, all additional kWhs		$0.079300	$0.023056	$0.029693	
Residential Service Cares Base Power Supply Charge, all kWhs			$0.073771	$0.067245	
PPFAC Charge		$0.018250	$0.000000	$0.015699	
Discount		Varies	8.00	8.00	
Average Sales per Month					
0	30%	$6.50	$0.00	$7.70	18.46%
50	30%	$7.96	$0.00	$7.70	-3.32%
100	30%	$11.38	$8.38	$9.96	-12.43%
200	30%	$18.21	$17.07	$20.23	11.10%
400	20%	$36.42	$34.43	$40.75	11.91%
600	20%	$52.02	$53.80	$63.28	21.64%
800	10%	$76.09	$73.16	$85.81	12.78%
1,000	10%	$93.65	$92.53	$108.34	15.69%
2,000	$8.00	$193.60	$189.35	$220.97	14.14%
2,500	$8.00	$242.38	$237.77	$277.29	14.41%
5,000	$8.00	$486.25	$479.84	$558.88	14.94%
10,000	$8.00	$974.00	$963.97	$1,122.06	15.20%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station (Permian Gas @ $7.50/mmBtu)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC	Total Estimated Increase %
Small General Service Delivery Charges - Mohave County				
Customer Charge	$10.00	$12.00	$12.00	
Energy Charge, first 400 kWhs	$0.074500	$0.027772	$0.036508	
Energy Charge, all additional kWhs	$0.074500	$0.037772	$0.046508	
Small General Service Base Power Supply Charge, all kWhs		$0.072656	$0.066228	
PPFAC Charge	$0.018250	$0.000000	$0.015699	
Average Sales per Month				
50	$14.64	$17.02	$17.92	22.44%
100	$19.28	$22.04	$23.84	23.70%
250	$33.19	$37.11	$41.61	25.37%
500	$56.38	$63.21	$72.22	28.10%
1,000	$102.75	$118.43	$136.44	32.78%
2,000	$195.50	$228.86	$264.87	35.48%
3,500	$334.63	$394.50	$457.52	36.73%
5,000	$473.75	$560.14	$650.18	37.24%
10,000	$937.50	$1,112.28	$1,292.35	37.85%
30,000	$2,792.50	$3,320.84	$3,861.05	38.27%
50,000	$4,647.50	$5,529.40	$6,429.75	38.35%
Small General Service Delivery Charges Santa Cruz County				
Customer Charge	$10.00	$12.00	$12.00	
Energy Charge, first 400 kWhs	$0.118300	$0.027772	$0.036508	
Energy Charge, all additional kWhs	$0.118300	$0.037772	$0.046508	
Small General Service Base Power Supply Charge, all kWhs		$0.072656	$0.066228	
PPFAC Charge	$0.018250	$0.000000	$0.015699	
Average Sales per Month				
50	$16.83	$17.02	$17.92	6.50%
100	$23.66	$22.04	$23.84	0.80%
250	$44.14	$37.11	$41.61	-5.73%
500	$78.28	$63.21	$72.22	-7.74%
1,000	$146.55	$118.43	$136.44	-6.90%
2,000	$283.10	$228.86	$264.87	-6.44%
3,500	$487.93	$394.50	$457.52	-6.23%
5,000	$692.75	$560.14	$650.18	-6.15%
10,000	$1,375.50	$1,112.28	$1,292.35	-6.05%
30,000	$4,106.50	$3,320.84	$3,861.05	-5.98%
50,000	$6,837.50	$5,529.40	$6,429.75	-5.96%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station (Permian Gas @ $7.50/mmBtu)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Large General Service Delivery Charges					
Customer Charge	$10.10	$11.10	$11.10		
Demand Charge, per kW	$9.50	$10.50	$10.50	50	
Energy Charge, per kWh	$0.053300	$0.007497	$0.013143		
Large General Service Base Power Supply Charge, all kWhs		$0.068363	$0.062315		
PPFAC Charge	$0.018250	$0.000000	$0.015699		
Average Sales per Month					
5,000	$842.85	$915.40	$991.89		17.68%
10,000	$1,200.60	$1,294.70	$1,447.67		20.58%
25,000	$2,273.85	$2,432.60	$2,815.03		23.80%
50,000	$4,062.60	$4,329.11	$5,093.96		25.39%
100,000	$7,640.10	$8,122.11	$9,651.82		26.33%
200,000	$14,795.10	$15,708.12	$18,767.54		26.85%
300,000	$21,950.10	$23,294.13	$27,883.26		27.03%
400,000	$29,105.10	$30,880.14	$36,998.98		27.12%
500,000	$36,260.10	$38,466.15	$46,114.70		27.18%
600,000	$43,415.10	$46,052.16	$55,230.42		27.21%

Large General Service TOU Delivery Charges					
Customer Charge	$15.00	$16.00	$16.00		
Demand Charge, per kW	$9.50	$10.50	$10.50	50	
Energy Charge, per kWh	$0.053300	$0.007497	$0.013143		
Large General Service (TOU) Base Power Supply Charge, all kWhs		$0.068363	$0.062315		
PPFAC Charge	$0.018250	$0.000000	$0.015699		
Average Sales per Month					
5,000	$847.75	$920.30	$996.79		17.58%
10,000	$1,205.50	$1,299.60	$1,452.57		20.50%
25,000	$2,278.75	$2,437.50	$2,819.93		23.75%
50,000	$4,067.50	$4,334.01	$5,098.86		25.36%
100,000	$7,645.00	$8,127.01	$9,656.72		26.31%
200,000	$14,800.00	$15,713.02	$18,772.44		26.84%
300,000	$21,955.00	$23,299.03	$27,888.16		27.02%
400,000	$29,110.00	$30,885.04	$37,003.88		27.12%
500,000	$36,265.00	$38,471.05	$46,119.60		27.17%
600,000	$43,420.00	$46,057.06	$55,235.32		27.21%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station (Permian Gas @ $7.50/mmBtu)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Large Power Service (<69KV) Delivery Charges					
Customer Charge	$365.00	$365.00	$365.00		
Demand Charge, per kW	$24.75	$21.53	$24.00	500	
Energy Charge, per kWh	$0.023600	$0.000000	$0.000000		
Large Power Service (<69KV) Base Power Supply Charge, all kWhs		$0.061534	$0.056090		
PPFAC Charge	$0.018250	$0.000000	$0.015699		
Average Sales per Month					
300,000	$25,295	$29,590.20	$33,901.00		34.02%
450,000	$31,573	$38,820.30	$44,669.32		41.48%
650,000	$39,943	$51,127.10	$59,027.08		47.78%
850,000	$48,313	$63,433.90	$73,384.83		51.90%
950,000	$52,498	$69,587.30	$80,563.71		53.46%
1,500,000	$75,515	$103,431.00	$120,047.55		58.97%
1,750,000	$85,978	$118,814.50	$137,994.74		60.50%
2,000,000	$96,440	$134,198.00	$155,941.94		61.70%
2,500,000	$117,365	$164,965.00	$191,836.34		63.45%

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Large Power Service (>69KV) Delivery Charges					
Customer Charge	$800.00	$400.00	$380.00		
Demand Charge, per kW	$16.10	$12.53	$15.00	500	
Energy Charge, per kWh	$0.023600	$0.000000	$0.000000		
Large Power Service (>69KV) Base Power Supply Charge, all kWhs		$0.061534	$0.056090		
PPFAC Charge	$0.018250	$0.000000	$0.015699		
Average Sales per Month					
300,000	$21,405.00	$25,125.20	$29,416.00		37.43%
450,000	$27,682.50	$34,355.30	$40,184.32		45.16%
650,000	$36,052.50	$46,662.10	$54,542.08		51.29%
850,000	$44,422.50	$58,968.90	$68,899.83		55.10%
950,000	$48,607.50	$65,122.30	$76,078.71		56.52%
1,500,000	$71,625.00	$98,966.00	$115,562.55		61.34%
1,750,000	$82,087.50	$114,349.50	$133,509.74		62.64%
2,000,000	$92,550.00	$129,733.00	$151,456.94		63.65%
2,500,000	$113,475.00	$160,500.00	$187,351.34		65.10%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station (Permian Gas @ $7.50/mmBtu)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Interruptible Power Service Delivery Charges					
Customer Charge	$10.10	$11.10	$11.10		
Demand Charge, per kW	$2.50	$3.50	$3.50	50	
Energy Charge, per kWh	$0.053300	$0.018268	$0.022967		
Interruptible Power Service Base Power Supply Charge, all kWhs		$0.062638	$0.057096		
PPFAC Charge	$0.018250	$0.000000	$0.015699		
Average Sales per Month					
10,001	$850.67	$995.24	$1,143.81		34.46%
15,000	$1,208.35	$1,399.69	$1,622.52		34.28%
20,000	$1,566.10	$1,804.22	$2,101.33		34.18%
30,000	$2,281.60	$2,613.28	$3,058.94		34.07%
50,000	$3,712.60	$4,231.41	$4,974.17		33.98%
75,000	$5,501.35	$6,254.06	$7,368.20		33.93%
100,000	$7,290.10	$8,276.71	$9,762.24		33.91%
125,000	$9,078.85	$10,299.36	$12,156.27		33.90%
150,000	$10,867.60	$12,322.02	$14,550.30		33.89%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

EXHIBIT
UNSE-45
Admitted

UNSE EXHIBIT

Estimated Rates with BMGS, a Solid Fuel Resource and Permian Gas @ $7.50

For Period June 2008 – May 2009

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station and Solid Fuel Resource ($7.50/mmBtu Gas)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC	Total Estimated Increase %
Residential Service Delivery Charges - Mohave County				
Customer Charge	$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs	$0.07490	$0.013056	$0.019693	
Energy Charge, all additional kWhs	$0.07490	$0.023056	$0.029693	
Residential Service Base Power Supply Charge, all kWhs		$0.073771	$0.067245	
PPFAC Charge	$0.01825	$0.000000	$0.007406	
Average Sales per Month				
0	$6.50	$7.70	$7.70	18.46%
50	$11.16	$12.04	$12.42	11.29%
100	$15.82	$16.38	$17.13	8.34%
200	$25.13	$25.07	$26.57	5.73%
400	$43.76	$42.43	$45.44	3.83%
600	$62.39	$61.80	$66.31	6.28%
800	$81.02	$81.16	$87.17	7.60%
1,000	$99.65	$100.53	$108.04	8.42%
2,000	$192.80	$197.35	$212.39	10.16%
2,500	$239.38	$245.77	$264.56	10.52%
5,000	$472.25	$487.84	$525.42	11.26%
10,000	$938.00	$971.97	$1,047.14	11.63%
Residential Service Delivery Charges - Santa Cruz County				
Customer Charge	$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs	$0.079300	$0.013056	$0.019693	
Energy Charge, all additional kWhs	$0.079300	$0.023056	$0.029693	
Residential Service Base Power Supply Charge, all kWhs		$0.073771	$0.067245	
PPFAC Charge	$0.018250	$0.000000	$0.007406	
Average Sales per Month				
0	$6.50	$7.70	$7.70	18.46%
50	$11.38	$12.04	$12.42	9.14%
100	$16.26	$16.38	$17.13	5.41%
200	$26.01	$25.07	$26.57	2.15%
400	$45.52	$42.43	$45.44	-0.18%
600	$65.03	$61.80	$66.31	1.96%
800	$84.54	$81.16	$87.17	3.12%
1,000	$104.05	$100.53	$108.04	3.84%
2,000	$201.60	$197.35	$212.39	5.35%
2,500	$250.38	$245.77	$264.56	5.67%
5,000	$494.25	$487.84	$525.42	6.31%
10,000	$982.00	$971.97	$1,047.14	6.63%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station and Solid Fuel Resource ($7.50/mmBtu Gas)

		Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC	Total Estimated Increase %
Residential Service Cares - Delivery Charges Mohave County					
Customer Charge		$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs		$0.074900	$0.013056	$0.019693	
Energy Charge, all additional kWhs		$0.074900	$0.023056	$0.029693	
Residential Service Cares Base Power Supply Charge, all kWhs			$0.073771	$0.067245	
PPFAC Charge		$0.018250	$0.000000	$0.007406	
Discount		Varies	$8.00	$8.00	
Average Sales per Month					
0	30%	$6.50	$7.70	$7.70	18.46%
50	30%	$7.81	$7.70	$7.70	-1.41%
100	30%	$11.07	$8.38	$9.13	-17.49%
200	30%	$17.59	$17.07	$18.57	5.56%
400	20%	$35.01	$34.43	$37.44	6.94%
600	20%	$49.91	$53.80	$58.31	16.82%
800	10%	$72.92	$73.16	$79.17	8.58%
1,000	10%	$89.69	$92.53	$100.04	11.55%
2,000	$8.00	$184.80	$189.35	$204.39	10.60%
2,500	$8.00	$231.38	$237.77	$256.56	10.88%
5,000	$8.00	$464.25	$479.84	$517.42	11.45%
10,000	$8.00	$930.00	$963.97	$1,039.14	11.73%
Residential Service Cares - Delivery Charges Santa Cruz County					
Customer Charge		$6.50	$7.70	$7.70	
Energy Charge, first 400 kWhs		$0.079300	$0.013056	$0.019693	
Energy Charge, all additional kWhs		$0.079300	$0.023056	$0.029693	
Residential Service Cares Base Power Supply Charge, all kWhs			$0.073771	$0.067245	
PPFAC Charge		$0.018250	$0.000000	$0.007406	
Discount		Varies	8.00	8.00	
Average Sales per Month					
0	30%	$6.50	$0.00	$7.70	18.46%
50	30%	$7.96	$0.00	$7.70	-3.32%
100	30%	$11.38	$8.38	$9.13	-19.72%
200	30%	$18.21	$17.07	$18.57	1.99%
400	20%	$36.42	$34.43	$37.44	2.80%
600	20%	$52.02	$53.80	$58.31	12.08%
800	10%	$76.09	$73.16	$79.17	4.06%
1,000	10%	$93.65	$92.53	$100.04	6.83%
2,000	$8.00	$193.60	$189.35	$204.39	5.57%
2,500	$8.00	$242.38	$237.77	$256.56	5.85%
5,000	$8.00	$486.25	$479.84	$517.42	6.41%
10,000	$8.00	$974.00	$963.97	$1,039.14	6.69%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station and Solid Fuel Resource ($7.50/mmBtu Gas)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC	Total Estimated Increase %
Small General Service Delivery Charges - Mohave County				
Customer Charge	$10.00	$12.00	$12.00	
Energy Charge, first 400 kWhs	$0.074500	$0.027772	$0.036508	
Energy Charge, all additional kWhs	$0.074500	$0.037772	$0.046508	
Small General Service Base Power Supply Charge, all kWhs		$0.072656	$0.066228	
PPFAC Charge	$0.018250	$0.000000	$0.007406	
Average Sales per Month				
50	$14.64	$17.02	$17.51	19.60%
100	$19.28	$22.04	$23.01	19.40%
250	$33.19	$37.11	$39.54	19.13%
500	$56.38	$63.21	$68.07	20.75%
1,000	$102.75	$118.43	$128.14	24.71%
2,000	$195.50	$228.86	$248.28	27.00%
3,500	$334.63	$394.50	$428.50	28.05%
5,000	$473.75	$560.14	$608.71	28.49%
10,000	$937.50	$1,112.28	$1,209.42	29.01%
30,000	$2,792.50	$3,320.84	$3,612.27	29.36%
50,000	$4,647.50	$5,529.40	$6,015.12	29.43%
Small General Service Delivery Charges Santa Cruz County				
Customer Charge	$10.00	$12.00	$12.00	
Energy Charge, first 400 kWhs	$0.118300	$0.027772	$0.036508	
Energy Charge, all additional kWhs	$0.118300	$0.037772	$0.046508	
Small General Service Base Power Supply Charge, all kWhs		$0.072656	$0.066228	
PPFAC Charge	$0.018250	$0.000000	$0.007406	
Average Sales per Month				
50	$16.83	$17.02	$17.51	4.04%
100	$23.66	$22.04	$23.01	-2.71%
250	$44.14	$37.11	$39.54	-10.43%
500	$78.28	$63.21	$68.07	-13.04%
1,000	$146.55	$118.43	$128.14	-12.56%
2,000	$283.10	$228.86	$248.28	-12.30%
3,500	$487.93	$394.50	$428.50	-12.18%
5,000	$692.75	$560.14	$608.71	-12.13%
10,000	$1,375.50	$1,112.28	$1,209.42	-12.07%
30,000	$4,106.50	$3,320.84	$3,612.27	-12.04%
50,000	$6,837.50	$5,529.40	$6,015.12	-12.03%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station and Solid Fuel Resource ($7.50/mmBtu Gas)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Large General Service Delivery Charges					
Customer Charge	$10.10	$11.10	$11.10		
Demand Charge, per kW	$9.50	$10.50	$10.50	50	
Energy Charge, per kWh	$0.053300	$0.007497	$0.013143		
Large General Service Base Power Supply Charge, all kWhs		$0.068363	$0.062315		
PPFAC Charge	$0.018250	$0.000000	$0.007406		
Average Sales per Month					
5,000	$842.85	$915.40	$950.42		12.76%
10,000	$1,200.60	$1,294.70	$1,364.75		13.67%
25,000	$2,273.85	$2,432.60	$2,607.72		14.68%
50,000	$4,062.60	$4,329.11	$4,679.33		15.18%
100,000	$7,640.10	$8,122.11	$8,822.57		15.48%
200,000	$14,795.10	$15,708.12	$17,109.03		15.64%
300,000	$21,950.10	$23,294.13	$25,395.50		15.70%
400,000	$29,105.10	$30,880.14	$33,681.97		15.73%
500,000	$36,260.10	$38,466.15	$41,968.43		15.74%
600,000	$43,415.10	$46,052.16	$50,254.90		15.75%

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Large General Service TOU Delivery Charges					
Customer Charge	$15.00	$16.00	$16.00		
Demand Charge, per kW	$9.50	$10.50	$10.50	50	
Energy Charge, per kWh	$0.053300	$0.007497	$0.013143		
Large General Service (TOU) Base Power Supply Charge, all kWhs		$0.068363	$0.062315		
PPFAC Charge	$0.018250	$0.000000	$0.007406		
Average Sales per Month					
5,000	$847.75	$920.30	$955.32		12.69%
10,000	$1,205.50	$1,299.60	$1,369.65		13.62%
25,000	$2,278.75	$2,437.50	$2,612.62		14.65%
50,000	$4,067.50	$4,334.01	$4,684.23		15.16%
100,000	$7,645.00	$8,127.01	$8,827.47		15.47%
200,000	$14,800.00	$15,713.02	$17,113.93		15.63%
300,000	$21,955.00	$23,299.03	$25,400.40		15.69%
400,000	$29,110.00	$30,885.04	$33,686.87		15.72%
500,000	$36,265.00	$38,471.05	$41,973.33		15.74%
600,000	$43,420.00	$46,057.06	$50,259.80		15.75%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station and Solid Fuel Resource ($7.50/mmBtu Gas)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Large Power Service (<69KV) Delivery Charges					
Customer Charge	$365.00	$365.00	$365.00		
Demand Charge, per kW	$24.75	$21.53	$24.00	500	
Energy Charge, per kWh	$0.023600	$0.000000	$0.000000		
Large Power Service (<69KV) Base Power Supply Charge, all kWhs		$0.061534	$0.056090		
PPFAC Charge	$0.018250	$0.000000	$0.007406		
Average Sales per Month					
300,000	$25,295	$29,590.20	$31,413.24		24.19%
450,000	$31,573	$38,820.30	$40,937.68		29.66%
650,000	$39,943	$51,127.10	$53,636.93		34.29%
850,000	$48,313	$63,433.90	$66,336.18		37.31%
950,000	$52,498	$69,587.30	$72,685.81		38.46%
1,500,000	$75,515	$103,431.00	$107,608.75		42.50%
1,750,000	$85,978	$118,814.50	$123,482.81		43.62%
2,000,000	$96,440	$134,198.00	$139,356.88		44.50%
2,500,000	$117,365	$164,965.00	$171,105.00		45.79%

Large Power Service (>69KV) Delivery Charges					
Customer Charge	$800.00	$400.00	$380.00		
Demand Charge, per kW	$16.10	$12.53	$15.00	500	
Energy Charge, per kWh	$0.023600	$0.000000	$0.000000		
Large Power Service (>69KV) Base Power Supply Charge, all kWhs		$0.061534	$0.056090		
PPFAC Charge	$0.018250	$0.000000	$0.007406		
Average Sales per Month					
300,000	$21,405.00	$25,125.20	$26,928.24		25.80%
450,000	$27,682.50	$34,355.30	$36,452.68		31.68%
650,000	$36,052.50	$46,662.10	$49,151.93		36.33%
850,000	$44,422.50	$58,968.90	$61,851.18		39.23%
950,000	$48,607.50	$65,122.30	$68,200.81		40.31%
1,500,000	$71,625.00	$98,966.00	$103,123.75		43.98%
1,750,000	$82,087.50	$114,349.50	$118,997.81		44.96%
2,000,000	$92,550.00	$129,733.00	$134,871.88		45.73%
2,500,000	$113,475.00	$160,500.00	$166,620.00		46.83%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Year Ended June 30, 2006
Includes Black Mountain Generating Station and Solid Fuel Resource ($7.50/mmBtu Gas)

	Total Bill Present Rate	Total Bill as Proposed (a.)	Total Bill With BMGS and Estimated PPFAC		Total Estimated Increase %
Interruptible Power Service Delivery Charges					
Customer Charge	$10.10	$11.10	$11.10		
Demand Charge, per kW	$2.50	$3.50	$3.50	50	
Energy Charge, per kWh	$0.053300	$0.018268	$0.022967		
Interruptible Power Service Base Power Supply Charge, all kWhs		$0.062638	$0.057096		
PPFAC Charge	$0.018250	$0.000000	$0.007406		
Average Sales per Month					
10,001	$850.67	$995.24	$1,060.88		24.71%
15,000	$1,208.35	$1,399.69	$1,498.13		23.98%
20,000	$1,566.10	$1,804.22	$1,935.48		23.59%
30,000	$2,281.60	$2,613.28	$2,810.16		23.17%
50,000	$3,712.60	$4,231.41	$4,559.54		22.81%
75,000	$5,501.35	$6,254.06	$6,746.26		22.63%
100,000	$7,290.10	$8,276.71	$8,932.98		22.54%
125,000	$9,078.85	$10,299.36	$11,119.70		22.48%
150,000	$10,867.60	$12,322.02	$13,306.42		22.44%

Note a: Reflects change in Company's proposed allocation of purchased power from 100% Average and Peaks to 40% Average and Peaks, 60% Energy, as proposed in Bentley Erdwurm's Rebuttal Testimony.

UNS Electric Inc.'s
Proposed Hook Up Fee

Docket No. E. 04204-06-0783

Rules and Regulations

Add:

Section 2, Definitions:

"Service Connection Contribution" – A non-refundable contribution in aid of construction charged by the Company to an applicant to offset construction costs for a new electric service connection.

Add:

Section 6. B. 2.

2. Service Connection Contribution

   a. A Service Connection Contribution of $250.00 will be charged to an applicant for each new electric service connection.

   b. The Service Connection Contribution will be considered a non-refundable contribution in aid of construction.

   c. The Company will waive the Service Connection Contribution for single-family residential service if the house is constructed in accordance with UNS Electric's "Energy Smart Homes" efficiency standards or any successor home efficiency program.

Renumber existing Sections 6.B.2 and 6.B.3.

EXHIBIT
tabbies
UNSE-47
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-49: Please indicate whether Mr. Rigsby disagrees with any of the following statements.

a. UNS Electric is smaller than any of the companies used Mr. Rigsby's proxy group.
b. UNS Electric is growing faster than any of the companies used in Mr. Rigsby's proxy group.
c. UNS Electric has a speculative-grade credit rating.
d. UNS Electric currently owns no generation, other than the Valencia Units in Santa Cruz County.

If so, please explain in full the basis for his disagreement, and provide any support for his position.

Response: William A. Rigsby

Mr. Rigsby has no reason to disagree with any of the statements listed above.

EXHIBIT
tabbies
UNSE-48
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-43: Regarding Schedule WAR-6, is the growth variable used for Mr. Rigsby's constant growth DCF formula the 3.94 percent number in Column A, with the other columns being checks on that figure? If not, please explain how the results in the other columns factor into Mr. Rigsby's determination of the growth variable.

Response: William A. Rigsby

Yes.

EXHIBIT
UNSE-49
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-48: Please provide the market to book ratios for each of the eight proxy companies Mr. Rigsby uses in his DCF and CAPM analyses.

Response: William A. Rigsby

The market to book ratios of the electric service providers used in Mr. Rigsby's sample were exhibited on page 2 of Schedule WAR-4 (Column B) and are as follows:

COMPANY NAME	**MARKET/BOOK RATIO**
CH Energy Group	1.45
Cleco Corporation	1.78
Hawaiian Electric	1.87
MGE Energy, Inc.	1.97
Northeast Utilities	1.68
NSTAR	2.31
Puget Energy, Inc	1.37
UIL holdings	1.84

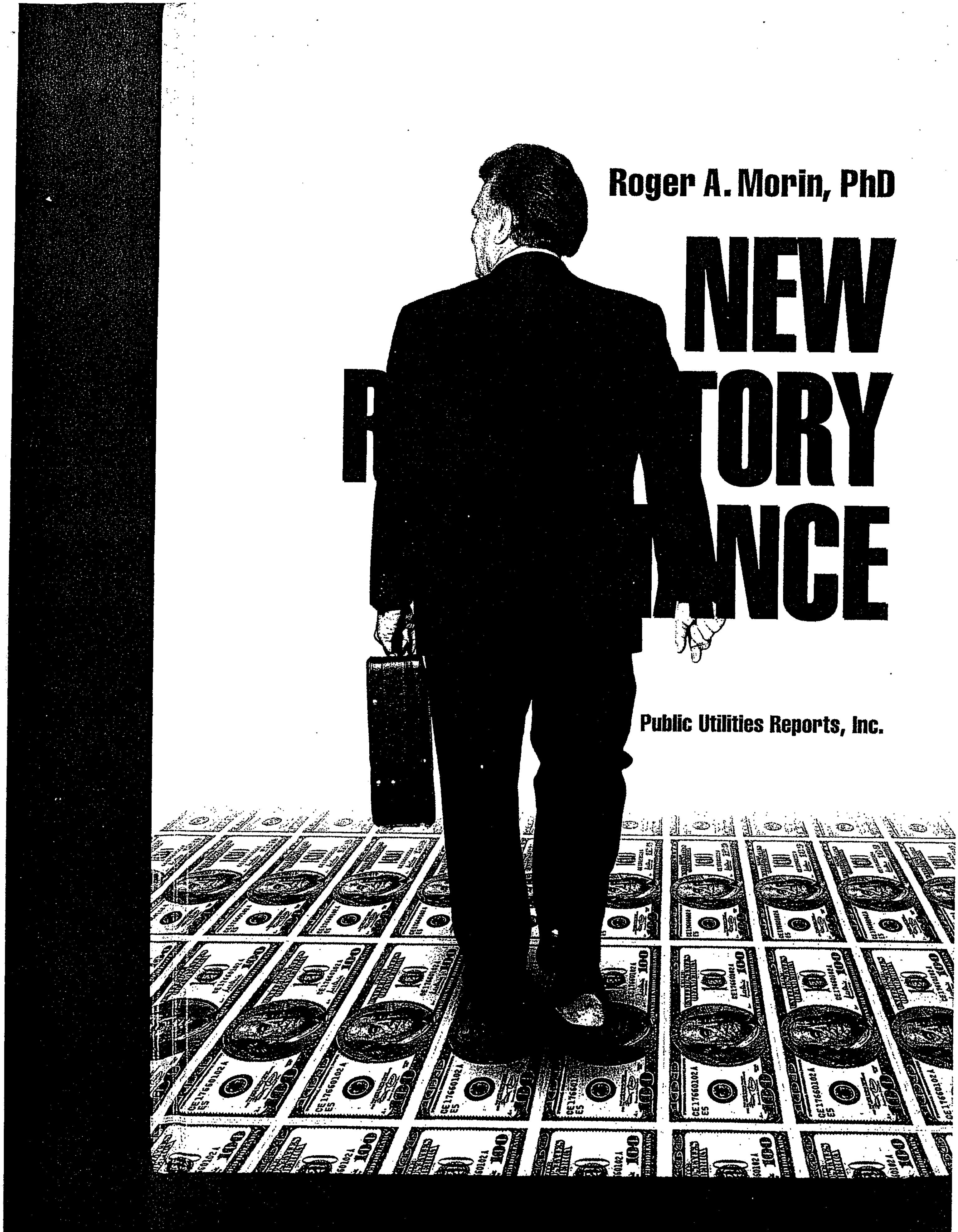
EXHIBIT
UNSE-50
Admitted

RUCO'S RESPONSE TO
UNS ELECTRIC, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783

UNSE 1-42: Please provide justification for the statement in Mr. Rigsby's Direct Testimony at page 17 that investor's expect a given utility will achieve a market-to-book ratio of 1.0.

Response: William A. Rigsby

The statement is based on the theoretical concept that the market to book ratio will gravitate toward a value of 1.0 over the long run if regulators award an allowed rate of return that is equal to the cost of capital. The concept is discussed in detail on pages 376 to 378 of Dr. Roger Morin's text <u>New Regulatory Finance</u> (attached).


Roger A. Morin, PhD
NEW
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NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

securities to the point at which new purchases would earn only the old cost of capital on their investments. The only beneficiaries would be those who happened to own the stock at the time the policy change was announced or anticipated.

12.5 M/B Ratios in the Regulatory Process

It is sometimes argued that because current M/B ratios are in excess of 1.0, this indicates that companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity, so that the stock price will decline to book value. It is therefore plausible, under this argument, that stock prices drop from the current M/B value to the desired M/B ratio range of 1.0 times book.

There are several reasons why this view of the role of M/B ratios in regulation should be avoided.

(1) The inference that M/B ratios are relevant and that regulators should set an ROE so as to produce an M/B of 1.0 is misguided. The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce an M/B of 1.0 presumes that investors are irrational. They commit capital to a utility with an M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is certainly not a realistic or accurate view of regulation. For example, assume a utility company with an M/B ratio of 1.5. If investors expect the regulator to authorize a return on book value equal to the DCF cost of equity, the utility stock price would decline to book value, inflicting a capital loss of some 30%. The notion that investors are willing to pay a price of 1.5 times book value only to see the market value of their investment drop by 30% is irrational.

(2) The condition that the M/B will gravitate toward 1.0 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis and absent inflation. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0 or higher with the proper allowance for flotation cost.

(3) A company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances that may affect the yields on securities of unregulated as well

as regulated enterprises. The achievement of a 1.0 M/B ratio is appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the M/B ratio is less than its long-run average under less favorable economic and capital market conditions.

Historically, the M/B ratio for utilities has fluctuated above and below 1.0. It has been consistently above 1.0 from the 1980s to the mid 2000s. This indicates that earnings below capital costs and M/B ratios below 1.0 during less favorable economic and capital market conditions must necessarily be accompanied with earnings in excess of capital costs and M/B ratios above 1.00 during more favorable economic and capital market conditions.

M/B ratios are determined by the marketplace, and utilities cannot be expected to compete for and attract capital in an environment where industrials are commanding M/B ratios well in excess of 1.0 while regulation reduces their M/B ratios toward 1.0. Moreover, if regulators were to currently set rates so as to produce an M/B ratio of 1.0, not only would the long-run target M/B ratio of 1.0 be violated, but more importantly, the inevitable consequence would be to inflict severe capital losses on shareholders. Investors have not committed capital to utilities with the expectation of incurring capital losses from a misguided regulatory process.

(4) Rate of return regulation is fundamentally a surrogate for competition. The fundamental goal of regulation should be to set the expected economic profit for a public utility equal to the level of profits expected to be earned by firms of comparable risk, in short, to emulate the competitive result. For unregulated firms, the natural forces of competition will ensure that in the long run, the ratio of the market value of these firms' securities equals the replacement cost of their assets. Competitive industrials of comparable risk to utilities have consistently been able to maintain the real value of their assets in excess of book value, consistent with the notion that, under competition, the Q-ratio will tend to 1.00 and not the M/B ratio. This suggests that a fair and reasonable price for a public utility's common stock is one that produces equality between the market price of its common equity and the replacement cost of its physical assets. The latter circumstance will not necessarily occur when the M/B ratio is 1.0. As the previous section demonstrated, only when the book value of the firm's common equity equals the value of the firm's equity at replacement assets will equality hold.

In an inflationary period, the replacement cost of a firm's assets may increase more rapidly than its book equity. To avoid the resulting economic confiscation of shareholders' investment in real terms, the allowed rate of return should produce an M/B ratio which provides a Q-ratio of 1 or a Q-ratio equal to that of comparable firms. It is quite plausible and likely that M/B ratios will exceed one if inflation increases the replacement cost of a firm's assets at a faster pace than historical cost (book equity). Perhaps this explains in part why utility M/B ratios have remained well above 1.0 over the past two decades. Are we to conclude that regulators have been systematically misguided all across the United States for all these years by awarding overgenerous returns, or are we to conclude that M/B ratios are largely immaterial in the context of ratemaking? The latter is more likely.

Historically, it has been highly unusual for utility stock prices to equal book value. Stock prices above book value are common for utility stocks, and indeed for all of the major market indexes. It is obvious that regulators, through their rate case decisions, and investors do not subscribe to the notion that utilities that have market prices above book value are over-earning. Otherwise, regulators would not grant rate increases for any utility whose stock price was above book value, and investors would never bid up the price of stock above book value. It is very difficult to accept the notion that, in a free-market economy with rampant competition, the vast majority of all publicly traded stocks are earning well in excess of their cost of capital.

In short, economic principles do not support the notion that the market value of utility shares should necessarily equal book value. A basic economic principle holds that, in the long run, market value should equal asset replacement cost in a given industry. In the presence of inflation and absent significant technological advances, replacement cost exceeds the original cost book value of assets. Consequently, it is quite reasonable for the market value of utility shares to exceed their book value and there is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition.

References

Brigham, E.F., Shome, D.K., and Bankston, T.A. "An Econometric Model for Estimating the Cost of Capital for a Public Utility." Public Utility Research Center Working Paper 5-79, University of Florida, 1979.

Callen, J.L. "Estimating the Cost of Equity Using Tobin's Q." *The Engineering Economist*, Summer 1988, 349–358.

Harlow, F. "Efficient Market Perspectives on Utility Rate of Return Adequacy." *Public Utilities Fortnightly,* March 29, 1984A, 38–40.

Harlow, F. "Q-Ratios and the Target Return on Equity for Utilities." *Public Utilities Fortnightly,* April 12, 1984B, 29–31.

EXHIBIT
UNSE-51
Admitted

**ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007**

1.23 **Please describe any rate cases in which Mr. Smith has recommended that CWIP be included in rate base. Please provide any and all portions of pre-filed testimony in any jurisdiction where Mr. Smith has recommended CWIP be included in rate base.**

RESPONSE: Mr. Smith has not compiled a comprehensive list, and to do so would be unreasonably burdensome and oppressive. However, in general, if a regulatory commission has stated a clear precedent for inclusion of CWIP in rate base, Mr. Smith would tend to follow such commission precedent unless there was a clear and compelling reason not to. As one illustrative example of where Mr. Smith included CWIP in rate base, based on his understanding of commission precedent in that jurisdiction, was Appalachian Power Company, Case No. PUE-2006-00065, before the Virginia State Corporation Commission.

RESPONDENT: Ralph Smith

WITNESS: Ralph Smith

ARIZONA CORPORATION COMMISSION'S RESPONSE TO UNS ELECTRIC, INC. FIRST SET OF DATA REQUESTS TO STAFF DOCKET NO. E-04204A-06-0783 August 1, 2007

1.35 **Does Mr. Smith believe that the Company will likely experience changes from year to year in annual expenses incurred in FERC Account Nos. 501, 547, 555 and 565 once the full requirements arrangement with PWCC expires in 2008?**

RESPONSE: Yes, Mr. Smith believes that the Company will likely experience changes in at least some of these accounts once the full requirements arrangement with PWCC expires in 2008.

RESPONDENT: Ralph Smith

WITNESS: Ralph Smith

ARIZONA CORPORATION COMMISSION'S RESPONSE TO UNS ELECTRIC, INC. FIRST SET OF DATA REQUESTS TO STAFF DOCKET NO. E-04204A-06-0783 August 1, 2007

1.40 **Does Mr. Smith believe that the completion cost for the Black Mountain Generating Station ("BMGS") will not equal at least $60 million? If so, please explain the basis for Mr. Smith's belief and provide any and all support for that belief.**

RESPONSE: Mr. Smith is aware that the Company has represented that BMGS will cost at least $60 million. He has no reason to believe that the ultimate cost of the plant would be below that Company cost estimate.

RESPONDENT: Ralph Smith

WITNESS: Ralph Smith

ARIZONA CORPORATION COMMISSION'S RESPONSE TO UNS ELECTRIC, INC.
SECOND SET OF REVISED DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 24, 2007

2.6 **Please provide a copy of Mr. Smith's testimony in Appalachian Power Company, Case No. PUE-2006-00065, before the Virginia State Corporation Commission, where he recommended that CWIP be included in rate base.**

RESPONSE: Objection: mischaracterizes the response. Without waiving the objection, see Attachment UNSE 2.6. In Mr. Smith's testimony in Case No. PUE-2006-00065, Mr. Smith did not attempt to present any type of evaluation of whether CWIP should or should not be included in rate base, but merely followed what he understood to be the longstanding precedent and practice of that particular state regulatory commission (the Virginia State Corporation Commission) and, because of that, included CWIP in his presentation of rate base in that case.

RESPONDENT: Maureen Scott, ACC Legal Division and Ralph Smith, Utilities Staff Consultant

WITNESS: Ralph Smith, Utilities Staff Consultant

EXHIBIT
UNSE-52
Admitted

**ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007**

1.2 **Mr. Taylor* for Staff notes – in his Engineering Report (June 15, 2007) at Page 11 that was attached to his June 28, 2007 Direct Testimony – that "UNS Electric is largely dependent on others through contract to provide power and transmit that power . . . . " Does Mr. Taylor believe that UNS Electric owning and operating the Black Mountain Generating Station ("BMGS") can provide enhanced reliability benefits over contracting for power? If so, please describe in detail those benefits. Can BMGS provide benefits to UNS Electric, from an engineering perspective, over UNS Electric purchasing its power?**

RESPONSE: Staff believes that owning and operating the BMGS could provide enhanced reliability benefits over contracting for power because the generating resource would be close to the load center. Also, the local generating source would be utilized to act as a Reliability Must-Run ("RMR") unit in the UNS Electric's ("UNS Electric" or "Utility") load pocket, thus improving the import capability of the system, a plus from an engineering perspective.

RESPONDENT: Prem Bahl

WITNESS: Prem Bahl

*Mr. Taylor is no longer with the Commission. Prem Bahl will be adopting Mr. Taylor's testimony and report in this case. Mr. Bahl has provided the responses to all data requests dealing with Mr. Taylor's testimony and engineering report in this case.

ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007

1.3 **Does Mr. Taylor for Staff believe that BMGS can provide RMR benefits and reduce the need for additional transmission in the area? Does Mr. Taylor believe that BMGS can provide other benefits, ancillary and/or otherwise, to UNS Electric and its customers? Would BMGS reduce the need to rely on purchased power and diversify UNS Electric's portfolio?**

RESPONSE: Yes, the BMGS would provide RMR and other benefits such as ancillary services in the Mohave county area encompassing UNS Electric's service territory, and reduce the need for additional transmission in the area and the need to rely on purchased power only to the extent of the peaking capacity of the generating plant. Staff believes that BMGS would reduce the need to rely on purchased power to the extent of UNS Electric's peak load requirements relative to the unit capacity, and it would be a beneficial addition to UNS Electric's existing generation portfolio.

RESPONDENT: Prem Bahl

WITNESS: Prem Bahl

ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007

1.4 **Does Mr. Taylor for Staff believe that BMGS will be a more efficient plant in terms of heat efficiency and use of resources such as natural gas and water?**

RESPONSE: UNS Electric has not provided to Staff any specifications of the plant in terms of its heat efficiency, other than the fact that it is a simple cycle combustion turbine, which is not as efficient as a combined cycle unit.

RESPONDENT: Prem Bahl

WITNESS: Prem Bahl

1.5 **Does Mr. Taylor for Staff believe that – given the customer base growth rates UNS Electric has experienced – additional transmission, distribution and/or generation facilities will be needed to serve the continued load growth expected for UNS Electric's service territories?**

RESPONSE: Yes.

RESPONDENT: Prem Bahl

WITNESS: Prem Bahl

EXHIBIT
UNSE-53
Admitted

ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007

1.6 **Regarding Exhibit 4 of Mr. Taylor's Engineering Report, please describe whether Mr. Taylor believes the following projects are either presently serving existing customers or will be serving existing customers before the conclusion of this rate case:**

a. UNSE Valencia Turbine No. 4.
b. West Golden Valley Substation.
c. Systems Integration Projects.
d. Griffith to North Havasu 230 kV line.

Further, please also describe whether Mr. Taylor believes these projects are designed to create additional revenue or will have an impact on maintenance and operation test-year expenses.

RESPONSE:

a. All the upgrades associated with the Valencia Turbine 4 will not be completed until Fall of 2007 and Spring of 2008. Therefore, it is not known whether all the existing customers of UNS Electric would be fully served before the conclusion of this rate case.

These projects do not appear to have any impact on UNS Electric's revenues or on maintenance and operation test-year expenses.

b. Yes.
c. Yes.
d. Griffith to North Havasu 230 kV line has two components ~ North Havasu-Franconia, and Griffith-Franconia. The Commission recently approved postponing construction of the Griffith-Franconia segment of the line. This project is presently serving the existing customers of UNS Electric, since UNS Electric recently signed a Network Service Agreement with the Western Area Power Administration ("WAPA"). Under this Agreement, WAPA could provide delivery of power to UNS Electric in the North Havasu area, which enabled the Utility to defer construction of the Griffith to Franconia portion of the project until 2012.

RESPONDENT: Prem Bahl

WITNESS: Prem Bahl

ARIZONA CORPORATION COMMISSION'S RESPONSE TO
UNS ELECTRIC, INC.
FIRST SET OF DATA REQUESTS TO STAFF
DOCKET NO. E-04204A-06-0783
August 1, 2007

1.7 **Mr. Taylor mentions "extensive bus upgrades in the Valencia substation and plans one transformer upgrade in the Fall of 2007 and further breaker upgrades through the Spring of 2008" in his Engineering Report at Page 21. Does Mr. Taylor believe the CWIP inclusion of $1,290,669.04 includes the description of items above, or that it only includes the work performed through June 30, 2006?**

RESPONSE: The amount of $1,290,669.04 associated with "extensive bus upgrades" in the Valencia Substation and the transformer upgrade in the Fall of 2007, and further upgrades through the Spring of 2008, are legitimately in the CWIP, and does not only include the work completed through June 30, 2006.

RESPONDENT: Prem Bahl

WITNESS: Prem Bahl

EXHIBIT
UNSE-54
Admitted

ESTABLISHMENT OF SERVICE (continued)

X. COMPANY-PROVIDED FACILITIES

1. The Company will provide, at no charge, an overhead service line up to one hundred fifty (150) feet and no more than one carryover pole, if required, for each Customer. The Company will provide, install, and connect, at no charge, underground service cable up to one hundred fifty (150) feet for each residential Customer.

2. The cost of any service line in excess of that allowed at no charge shall be paid for by the Customer as a contribution in aid of construction.

3. A Customer requesting an underground service line in an area served by overhead facilities shall pay for the difference between an overhead service connection and the actual cost of the underground connection as a nonrefundable contribution.

Y. EASEMENTS AND RIGHTS-OF-WAY

1. Each Customer shall grant adequate easements and rights-of-way satisfactory to the Company necessary for Customer's proper service connection. Failure on the part of the Customer to grant adequate easement and right-of-way shall be grounds for the Company to refuse service.

2. When the Company discovers that a Customer or the Customer's agent is performing work or has constructed facilities adjacent to or within an easement or right-of-way and such work, construction or facility poses a hazard or is in violation of federal, state or local laws, ordinances, statutes, rules or regulations, or significantly interferes with the Company's access to equipment, the Company shall notify the Customer or the Customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer's expense.

EXHIBIT
tabbies
UNSE-55
Admitted

SECTION 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

B. Service Lines

1. Customer provided facilities

a. Each Applicant for services will be responsible for all inside wiring including the service entrance and meter socket. For three-phase service, the Customer will provide, at the Customer's expense, all facilities including conductors and conduit, beyond the Company-designated point of delivery.

b. Meters and service switches in conjunction with the meter will be installed in a location where the meters will be readily and safely accessible for reading, testing and inspection, where these activities will cause the least interference and inconvenience to the Customer. Location of metering facilities will be determined by the Company and may or may not be at the same location as the point of delivery. However, the meter locations will not be on the front exterior wall of the home, or in the carport or garage unless mutually agreed to between the Customer or homebuilder and the Company. Without cost to the Company, the Customer must provide, at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

c. Where the meter or service line location on the Customer's premises is changed at the request of the customer or due to alterations on the Customer's premises, the Customer must provide and have installed at the Customer's expense all wiring and equipment necessary for relocating the meter and service line connection. The Company may charge the Customer for moving the meter and/or service lines.

d. Customer will provide access to a main switch or breaker for disconnecting load to enable safe installation and removal of company meters.

2. Overhead Service Connection – Secondary Service

a. Where the Company's distribution pole line is located on the Customer's premises, or on a street, highway, lane, alley, road, or private easement immediately contiguous thereto, the Company will at its own expense, furnish and install a single span of service drop from its pole to the Customer's point of attachment, provided that this attachment is at the point of delivery and is of a type and so located that the service drop wires may be installed in a manner approved by the Company in accordance with good engineering practice, and in compliance with all applicable laws, ordinances, Rules and Regulations, including those governing clearances and points of attachments. For purposes of this Section, a single span of service drop as described above is no more than 100 feet in length and will not include a carryover pole.

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b. Whenever any of the clearances required by the applicable laws, ordinances, rules or regulations of public authorities or standards of the Company from the service drops to the ground or any object become impaired by reason of any changes made by the owner or tenant of the premises, the Customer will, at his own expense, provide a new and

EXHIBIT
UNSE-56
Admitted

SECTION 9
LINE EXTENSIONS

Introduction

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities beyond this distance.

All extensions are made on the basis of economic feasibility. Footage and revenue basis are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within these footage and dollar units.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.

In unusual circumstances, when the application of the provisions of this policy appear impractical, or in case Customer's requirements exceed 100 kW, the Company will make a special study of the conditions to determine the basis on which service may be rendered.

A. General Requirements

1. Upon request by an Applicant for a line extension, the Company will prepare without charge, a preliminary sketch and rough estimates of the cost of installation, if any, to be paid by said applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company will, upon request, make available within ninety (90) days after receipt of the deposit referred to above, those plans, specifications, or cost estimates of the proposed line extension. Where the applicant authorizes the Company to proceed with construction of the extension, the deposit will be credited to the cost of construction, otherwise the deposit will be non-refundable. If the extension is to include over sizing of facilities to be done at the Company's expense, appropriate details will be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved plats will be provided with plans, specifications, or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

3. Where the Company requires an Applicant to advance funds for a line extension, the Company will furnish the Applicant with a copy of the line extension Pricing Plans prior to the Applicant's acceptance of the Company's extension agreement.

SECTION 9
LINE EXTENSIONS
(continued)

4. All line extension agreements requiring payment of an advance by the Applicant will be in writing and signed by each party.

5. The provisions of this rule apply only to those Applicants who, in the Company's judgment, will be permanent Customers. Extension of facilities will not begin until the satisfactory completion of required site improvements, as determined by the Company, and an approved service entrance to accept electric service has been installed.

B. Minimum Written Agreement Requirements

1. Each line extension agreement must, at a minimum, include the following information:

    a. Name and address of applicant(s);

    b. Proposed service address(es) or location(s);

    c. Description of requested service;

    d. Description and sketch of the requested line extension;

    e. A cost estimate to include materials, labor, and other costs as necessary;

    f. Payment terms;

    g. A concise explanation of any refunding provisions, if applicable;

    h. The Company's estimated start date and completion date for construction of the line extension; and

    i. A summary of the results of the economic feasibility analysis performed by the Company to determine the amount of advance required from the applicant for the proposed line extension.

2. Each Applicant will be provided with a copy of the written line extension agreement.

SECTION 9
LINE EXTENSIONS
(continued)

C. Line Extension Costs

1. Calculations of estimated line extension costs will include the following:

   a. Material cost;

   b. Direct labor cost; and

   c. Overhead cost;

Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs including but not limited to:

Indirect labor
Engineering
Transportation
Taxes (e.g. FICA, State & Federal Unemployment which are properly allocated to construction)
Insurance
Stores expense
General office expenses allocated to costs of construction
Power operated equipment
Employee Pension and Benefits
Vacations and Holidays
Miscellaneous expenses properly chargeable to construction

D. Conditions Governing Extensions Of Electric Distribution Lines And Services

Line extension measurements will be along the route of construction required, but no free distance will be permitted beyond the shortest reasonable route to the nearest reasonable point of sevice on each Customer's premises as determined by the Company. This measurement will include primary and secondary lines.

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1. Footage Basis:

   a. The Company will extend single phase overhead distribution facilities without charge to any Customer whom the Company considers permanent (except irrigation customers) provided that the length of extension does not exceed four hundred (400) feet.

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SECTION 9
LINE EXTENSIONS
(continued)

b. The Company will make extensions in excess of four hundred (400) feet provided:

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(i) The economic feasibility study in subsection 9.E. has been completed and the Company determines that the extension is feasible;

(ii) A line extension agreement has been signed by each party;

(iii) The Company has received a non-interest bearing, refundable construction advance and/or contribution in aid of construction, if required, to cover cost of construction; and

(iv) The extension does not exceed a total construction cost of $25,000.

c. Customer advances of over $50.00, as collected under the terms of extensions beyond the free distance, are subject to refund, provided that, within a five (5) year period after signing the extension agreement, Customer requests a survey to determine if additional Customers have been connected to and are using service from the extension.

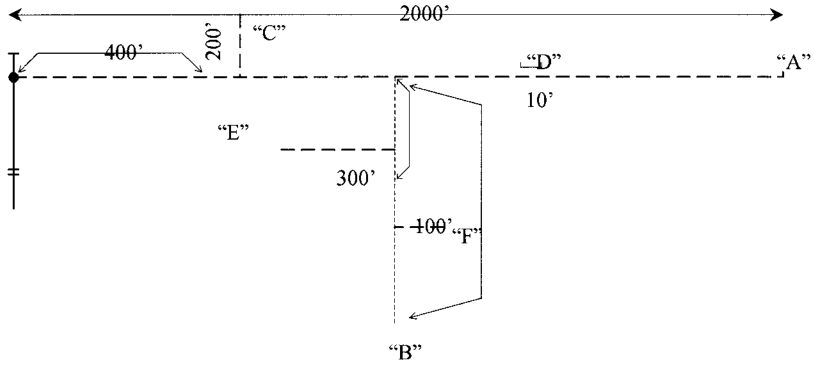
If this survey discloses that additional Customers or load are connected to the extension (not including laterals or extensions over the free distance) and are so located that, had they been there at the time the extension was made, the amount of advance would have been reduced or eliminated, then a readjustment will be made and Company will refund the difference between the amount actually advanced and the amount of the advance had it been determined at the time of survey. The amount of the refund will be based on the cost of constructing the original line.

(i) Only one survey will be made annually for each extension. In no case will the total of refund payments exceed the amount originally advanced.

(ii) If after five (5) years from receipt, the construction advance has not been totally refunded, that advance will be considered a contribution in aid of construction and no longer be refundable.

SECTION 9
LINE EXTENSIONS
(continued)

(iii) A pictorial explanation of the method of refund used for the footage basis is as follows:



SECTION 9
LINE EXTENSIONS
(continued)

500'

Applicant "A" - Customer makes refundable advance per footage over 400 feet (1,600' @ estimated line extension cost per foot).

Applicant "B" - Customer makes refundable advance for footage over 400 feet (1,100' @ estimated line extension cost per foot). No refund is due Applicant "A" because total construction was over 400 feet.

Applicant "C" - No charge to Customer. However if within the five (5) year period Customer "A" will receive refund (200' @ original cost per foot to Customer "A"). Line "C" ties directly into Line "A" and it is under 400 feet.

Applicant "D" - No charge to Customer. If within the five (5) year period Customer "A" will receive a refund (390' @ original cost per foot to Customer "A").

Applicant "E" - No charge to Customer. If within five (5) years from date of advance from Customer "B", Customer "B" will get a refund (100' @ original cost per foot to Customer "B"). Line "E" ties directly into Line "B".

Applicant "F" - No charge to Customer. If within five (5) years from date of advance from Customer "B", Customer "B" will get a refund (300' @ original cost per foot to Customer "B").

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EXHIBIT
UNSE-57
Admitted

SECTION 9
LINE EXTENSIONS

Introduction

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities beyond this distance.

All extensions are made on the basis of economic feasibility. Footage and revenue basis are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within these footage and dollar units.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A standard policy has been adopted to provide service to Customers whose requirements are deemed by the Company to be economical and ordinary in nature.

In unusual circumstances, when the application of the provisions of this policy appear impractical, or in case Customer's requirements exceed 100 kW, the Company will make a special study of the conditions to determine the basis on which service may be rendered.

A. General Requirements

1. Upon request by an Applicant for a line extension, the Company will prepare without charge, a preliminary sketch and rough estimates of the cost of installation, if any, to be paid by said applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company will, upon request, make available within ninety (90) days after receipt of the deposit referred to above, those plans, specifications, or cost estimates of the proposed line extension. Where the applicant authorizes the Company to proceed with construction of the extension, the deposit will be credited to the cost of construction, otherwise the deposit will be non-refundable. If the extension is to include over sizing of facilities to be done at the Company's expense, appropriate details will be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved plats will be provided with plans, specifications, or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

3. Where the Company requires an Applicant to advance funds for a line extension, the Company will furnish the Applicant with a copy of the line extension Pricing Plans prior to the Applicant's acceptance of the Company's extension agreement.

SECTION 9
LINE EXTENSIONS
(continued)

C. Line Extension Costs

1. Calculations of estimated line extension costs will include the following:

   a. Material cost;

   b. Direct labor cost; and

   c. Overhead cost;

Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs including but not limited to:

Indirect labor
Engineering
Transportation
Taxes (e.g. FICA, State & Federal Unemployment which are properly allocated to construction)
Insurance
Stores expense
General office expenses allocated to costs of construction
Power operated equipment
Employee Pension and Benefits
Vacations and Holidays
Miscellaneous expenses properly chargeable to construction

D. Conditions Governing Extensions Of Electric Distribution Lines And Services

Line extension measurements will be along the route of construction required, but no free distance will be permitted beyond the shortest reasonable route to the nearest reasonable point of sevice on each Customer's premises as determined by the Company. This measurement will include primary and secondary lines.

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1. Footage Basis:

   a. The Company will extend single phase overhead distribution facilities without charge to any Customer whom the Company considers permanent (except irrigation customers) provided that the length of extension does not exceed four hundred (400) feet.

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SECTION 9
LINE EXTENSIONS
(continued)

b. The Company will make extensions in excess of four hundred (400) feet provided:

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(i) The economic feasibility study in subsection 9.E. has been completed and the Company determines that the extension is feasible;

(ii) A line extension agreement has been signed by each party;

(iii) The Company has received a non-interest bearing, refundable construction advance and/or contribution in aid of construction, if required, to cover cost of construction; and

(iv) The extension does not exceed a total construction cost of $25,000.

c. Customer advances of over $50.00, as collected under the terms of extensions beyond the free distance, are subject to refund, provided that, within a five (5) year period after signing the extension agreement, Customer requests a survey to determine if additional Customers have been connected to and are using service from the extension.

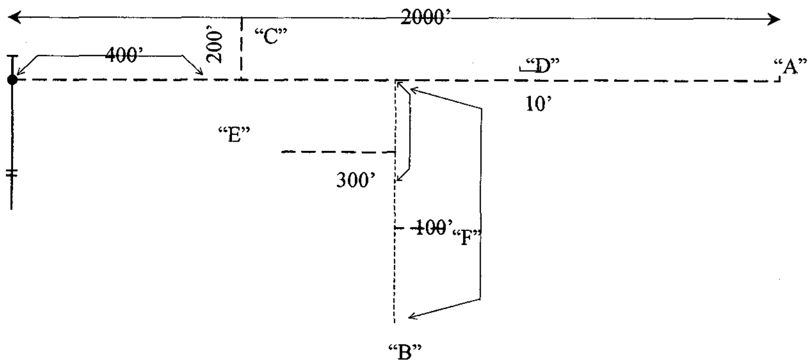
If this survey discloses that additional Customers or load are connected to the extension (not including laterals or extensions over the free distance) and are so located that, had they been there at the time the extension was made, the amount of advance would have been reduced or eliminated, then a readjustment will be made and Company will refund the difference between the amount actually advanced and the amount of the advance had it been determined at the time of survey. The amount of the refund will be based on the cost of constructing the original line.

(i) Only one survey will be made annually for each extension. In no case will the total of refund payments exceed the amount originally advanced.

(ii) If after five (5) years from receipt, the construction advance has not been totally refunded, that advance will be considered a contribution in aid of construction and no longer be refundable.

SECTION 9
LINE EXTENSIONS
(continued)

(iii) A pictorial explanation of the method of refund used for the footage basis is as follows:



SECTION 9
LINE EXTENSIONS
(continued)

500'

Applicant "A" - Customer makes refundable advance per footage over 400 feet (1,600' @ estimated line extension cost per foot).

Applicant "B" - Customer makes refundable advance for footage over 400 feet (1,100' @ estimated line extension cost per foot). No refund is due Applicant "A" because total construction was over 400 feet.

Applicant "C" - No charge to Customer. However if within the five (5) year period Customer "A" will receive refund (200' @ original cost per foot to Customer "A"). Line "C" ties directly into Line "A" and it is under 400 feet.

Applicant "D" - No charge to Customer. If within the five (5) year period Customer "A" will receive a refund (390' @ original cost per foot to Customer "A").

Applicant "E" - No charge to Customer. If within five (5) years from date of advance from Customer "B", Customer "B" will get a refund (100' @ original cost per foot to Customer "B"). Line "E" ties directly into Line "B".

Applicant "F" - No charge to Customer. If within five (5) years from date of advance from Customer "B", Customer "B" will get a refund (300' @ original cost per foot to Customer "B").

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SECTION 9
LINE EXTENSIONS
(continued)

2. Revenue Basis

   a. The Company will extend its overhead distribution facilities without charge to any Customer or group of Customers whom Company considers permanent (except irrigation customers) where the estimated annual revenue multiplied by two (2) is equal to or greater than the total cost of the extension. Extensions made on this basis may not exceed a total cost of $25,000.

   b. For extensions over free distance (revenue basis) Company will extend its distribution facilities up to a cost limitation of $25,000, provided Customer or Customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the balance of the construction cost is no greater than twice the estimated annual revenue. If the total advance is less than one hundred dollars ($100), the Company will waive the charge.

   c. Advances are subject to refund as specified in subsection 9.D.1.c.

3. Economic Feasibility Basis

   a. The Company will extend its overhead distribution facilities without charge to any Customer, or group of Customers, whom Company considers permanent (except irrigation customers) requiring an extension costing more than $25,000, after determination by Company that the volume of use makes the extensions economically feasible.

   b. Economic feasibility, as used in this policy, will mean a determination by Company that the revenue less the cost of service provides an adequate rate of return on the investment made by Company to serve Customer.

   c. For extensions costing more than $25,000 that do not show economic feasibility Company may, at its option, and after special study, extend its facilities provided that Customer or Customers will sign an extension agreement and advance as much of the cost of the extension and/or agree to pay a higher special rate (facilities charge) as is necessary to make the extension economically feasible.

   d. Advances are subject to refund as specified in subsection 9.D.1.c.

SECTION 9
LINE EXTENSIONS
(continued)

4. Underground Construction

   a. Installation of single phase underground electric lines to furnish permanent electric service to a duly recorded Residential Subdivision Development, in which facilities for electric service have not been constructed, for which applications are made by a developer, will be installed underground provided the following conditions are met:

      (i) An economic feasibility study has been completed and the Company determines that the extension is feasible;

      (ii) A line extension agreement has been signed by developer(s) and the Company;

      (iii) Receipt of a non-interest bearing, refundable construction advance with the Company to cover total cost of construction. The construction advance will be considered a contribution in aid of construction if it has not been totally refunded after five (5) years in accordance with subsection D.1.c.(ii) above;

      (iv) The developer will provide the trenching, bedding, backfill (including any imported backfill required), compaction, repaving and any earthwork for pull boxes and transformer pad sites required in accordance with the specifications and schedules of the Company;

      (v) Right-of-way and easements satisfactory to the Company will be furnished by the developer at no cost to the Company and in reasonable time to meet service requirements. No underground electric facilities will be installed by the Company until the final grades have been established and furnished to the Company. In addition the easements, alleys and/or streets must be graded to within six (6) inches of final grade by the developer before the Company will commence construction. This clearance and grading must be maintained by the developer. If, subsequent to construction, the clearance or grade is changed in such a way as to require relocation of underground facilities or results in damage to those facilities, the cost of the relocation and/or resulting repairs will be borne by the developer;

      (vi) If armored cable or special cable covering is required, the Customer or developer will make a non-refundable contribution equal to the additional cost of such cable or covering;

      (vii) Underground service lines to residential customers will be installed, owned, operated, and maintained by the Company. The Customer will be required to provide, at the Customer's expense, all necessary conduit, trenching, backfilling, compaction, and concrete work, if required. in accordance with Company specifications and other local codes; and

SECTION 9
LINE EXTENSIONS
(continued)

(viii) Underground residential service lines not installed in accordance with Company specifications will be repaired and/or replaced by the Company at the Customer's expense.

b. Three-Phase underground construction: Where three-phase underground service is requested by a Customer, the Company will install required facilities provided:

(i) An economic feasibility study has been completed and the Company determines that the extension is feasible;

(ii) A line extension agreement has been signed by each party;

(iii) Conditions specified in subsections 9.D.4.a.(iv) through (vi) are met;

(iv) A non-refundable contribution equal to the estimated difference in cost of construction between overhead and underground facilities has been deposited with the Company and

(v) The Customer will provide and install transformer and/or switchgear pads and conduit in accordance with Company specifications.

c. The Customer will retain ownership of all non-residential single phase service lines and three phase service lines and will maintain these lines at no cost to the Company. Any work performed by the Company on Customer-owned facilities will be at actual cost. Non-residential properties include, but are not limited to master-metered apartment buildings and duplexes.

5. Other Customers

a. Irrigation Customers - Customers requiring construction of electric facilities for service to irrigation pumping will advance the total construction cost, which may include a portion of the shared backbone cost from designated irrigation substations, less the first $500 of construction. Customer advances, as collected under these terms, are subject to refunds of twenty percent (20%) of that portion of the annual accumulation of twelve (12) monthly bills, commencing with the service date, in excess of the minimum, provided, however, that no refunds will be made after five years from the effective date of the agreement for service. In no case will the total of refund payments exceed the amount originally advanced.

SECTION 9
LINE EXTENSIONS
(continued)

b. Doubtful Permanency Customers - When, in the opinion of the Company, permanency of the Customer's service is doubtful, the Customer will be required to advance the total construction cost, including transformer and service installation. Advances are subject to full or partial refund pursuant to surveys based on the revenue or economic feasibility basis. In no event, will the refund exceed twenty percent (20%) of the annual accumulation of twelve (12) monthly bills in excess of the annual minimum bill for the Customer as specified in the extension agreement. No refunds will be made after five (5) years from the effective date of the agreement for service. In no event will the total refund payments exceed the amount originally advanced.

c. Temporary Customers - Where a temporary meter or construction is required to provide service to a Customer, then the Customer, in advance of installation or construction, will make a contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of those facilities. When the use of service is discontinued or agreement for service is terminated, the Company may dismantle its facilities and the materials and equipment provided by the Company will be salvaged and remain its property.

   Each applicant for temporary service may be required to deposit with the Company a sum of money equal to the estimated amount of the Company's bill for such service, or to otherwise secure in a manner satisfactory to the Company, the payment of any bill which may accrue by reason of such service so furnished or supplied. Contributions for temporary service are not refundable.

d. Speculative Customers - Service to mining and milling installations and similar speculative businesses, where special conditions prevail as to service requirements and/or construction cost for line extension, will be furnished under special contract.

e. Real Estate Development - Extensions of electric facilities to and within real estate developments including residential subdivisions, industrial parks, mobile home parks, apartment complexes, planned area developments and shopping centers may be made in advance of application for service by permanent Customers after the Company and the developer of said subdivision have entered into a written contract and the total estimated installed cost of the distribution facilities is advanced to the Company as a refundable non-interest bearing cash deposit to cover the Company's cost of construction. Refunds will be made in accordance with provisions in the written contract and be based on an economic feasibility study.

f. Seasonal Customers - Extensions of electric facilities to a Customer's premises which will be continuously occupied less than nine (9) months out of each twelve (12) month period may be made only on the basis of economic feasibility.

SECTION 9
LINE EXTENSIONS
(continued)

6. Other Conditions

   a. Three Phase Service - Where a Customer requests three phase service and it is necessary to convert all or a portion of an existing overhead or underground distribution system from single phase to three phase in order to furnish this service, the entire cost of the conversion will be paid by the Customer, should the Company determine, through an economic feasibility study, that the extension is not feasible.

   b. Request For Additional Facilities - The Company will install only those facilities which it deems are necessary to render service in accordance with its rate schedules. Where the Customer requests facilities which are in addition to, or in substitution for, the standard facilities which the Company normally would install, the extra cost thereof will be paid by the Customer.

   c. Primary Service And Metering - The Company will provide primary service to a point of delivery and that point of delivery will be determined by the Company. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The system will be treated as primary service for the purposes of billing. The Company reserves the right to approve or require modification to the Customer's distribution system prior to installation, and the Company will determine the voltage available for primary service. Instrument transformers, metering riser poles and associated equipment to be installed and maintained by the Company may be at the Customer's expense.

   d. Rights-Of-Way - All necessary easements or rights-of-way required by the Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the Customer, developer, or others will be furnished in the Company's name by the Customer without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of the Company will contain only those terms and conditions that are acceptable to the Company.

   e. Change Of Grade - If subsequent to construction of electric distribution and/or transmission lines and services, the final grade established by the Customer or developer is changed in such a way as to require relocation of the Company facilities or results in damage to those same facilities, the cost of relocation and/or resulting repairs will be borne by the Customer or developer.

   f. Relocation - When the Company is requested to relocate its facilities for the benefit and/or convenience of a Customer, the Customer will pay the Company for the total cost of the work to be performed prior to the start of construction.

SECTION 9
LINE EXTENSIONS
(continued)

g. Connecting Or Disconnecting Customer's Service - Only duly authorized employees of the Company are allowed to connect the Customer's service to, or disconnect the same from, the Company's electric lines.

h. Maintenance Of Customer's Equipment - The Customer will, at the Customer's own risk and expense, furnish, install and keep in good and safe condition all electrical wires, lines, machinery and apparatus which may be required for receiving electric energy from the Company, and for applying and utilizing that energy, including all necessary protective appliances and suitable building therefore, and the Company will not be responsible for any loss or damage occasioned or caused by the negligence, want of proper care, or wrongful act of the Customer or any of the Customer's agents, employees or licensees on the part of the Customer in installing, maintaining, using, operating or interfering with any such wires, lines, machinery or apparatus.

i. Entering Customers Premises - The Company will at all times have the right of ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of electric energy and the exercise of any and all rights secured to it by law or these Rules and Regulations.

j. Removal Of Company Property - As provided for in these Rules and Regulations, the Company will have the right to remove any and all of its property installed on the Customer's premises at the termination of service.

k. Resale Of Energy - Unless specifically agreed upon, the Customer must not resell any of the electric energy received by the Customer from the Company to any other person, or for any other purpose or on other premises than specified in the Customer's application for service.

SECTION 9
LINE EXTENSIONS
(continued)

l. Supply Of Electric - The Company will exercise reasonable diligence and care to furnish and deliver a continuous and sufficient supply of electric energy to the Customer, and to avoid any shortage or interruption of delivery of same. The Company will not be liable for interruption or shortage or insufficiency of supply, or any loss or damage occasioned thereby, if same is caused by inevitable accident, act of God, fire, strikes, riots, war, or any other cause not within its control. The Company, whenever it must find it necessary for the purpose of making repairs or improvements to its system, will have the right to suspend, temporarily, the delivery of electric energy, but in all such cases as reasonable notice thereof as circumstances will permit will be given to the Customers. The making of these repairs or improvements will proceed as rapidly as may be practicable, and, if practicable, at those times that will cause the least inconvenience to the Customers. In case of shortage of supply, the Company will have the right to give preference in the matter of furnishing electric service to the United States and the State of Arizona, and cities, cities and counties, counties and towns, their inhabitants for lighting and for public purposes and to other public utilities and those engaged in public or quasi-public service if necessary.

m. Change of Customer's Requirements - In the event that the Customer must make any material change either in the amount or character of the appliances or apparatus installed upon the Customers premises to be supplied with electric energy by the Company, the Customer must immediately give the Company written notice to this effect.

n. Power Factor - In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety percent (90%).

o. Refunds - In no case will the total of any refund payments made by the Company exceed the amount of any construction advance.

p. Collections - Nothing in these Rules and Regulations will be construed as limiting or in any way affecting the right of the Company to collect from the Customer any other additional sum of money which may become due and payable.

SECTION 9
LINE EXTENSIONS
(continued)

E. Economic Feasibility Criteria

Description of Service Request

Number of Customers Requesting Service
Location
Feet of Primary Distribution Line Needed

1. Computation Of Cost Of Construction

a. Materials . . . . $ . . . .

b. Labor. . . . . $ . . . .

c. Total Direct Cost (Line 1.a + 1.b) . . . .$ . . . .

d. Payroll Taxes and Insurance
(______ % x Line 1.b) (Company Labor Only) . . . . . $ . . . .

e. Engineering and Superintendence
(______% x (Line 1.c + 1.d)) . . . . $. . . . .

f. Interest During Construction
(______ % x (Line 1.c + 1.d + 1.e)) . . . .$ . . . .

g. Total Cost of Construction
(Line 1.c + 1.d + 1.e + 1.f) . . . .$ . . . .

SECTION 9
LINE EXTENSIONS
(continued)

2. Computation Of Operating Revenues

   a. Estimated Monthly kWh/Customer. . . . .

   b. Monthly Revenue/Customer
   (Pricing Plan ________). . . . . $. . . . .

   c. Total Customers. . . . .

   d. Total Monthly Revenue
   (Line 2.b x 2.c). . . . .$ . . . .

   e. Total Annual Operating Revenue
   (Line 2.d x 12). . . . . $. . . . .

3. Computation Of Operating Expenses

   a. Depreciation
   Line 1.g x ______ %. . . . . $. . . . .

   b. Operation and Maintenance
   Line 1.g x ______ % . . . .$ . . . .

   c. Taxes
   Line 1.g x ______% x $_____/$100 . . . . . . $. . . . .

   d. Power Costs
   ______ kWh x $______ . . . . $. . . . .

   e. Total Annual Operating Expense
   (Line 3.a + 3.b + 3.c +3.d) . . . . $. . . . .

4. Computation Of Operating Income (Loss) Before Income Taxes

   a. Annual Operating Revenues (Line 2.e) . . . . $. . . . .

   b. Annual Operating Expenses (Line 3.e) . . . . .$. . . . .

   c. Annual Operating Income (Loss) B.I.T . . . . .$. . . . .

SECTION 9
LINE EXTENSIONS
(continued)

5. Computation Of Credit To Construction Cost

   a. If Line 4.c shows a Net Loss Amount no credit is allowed toward the construction cost, and the customer(s) desiring service must advance the total cost of construction as shown of Line 1.g.

   b. If Line 4.c shows an Operating Income Before Income Taxes amount, a credit toward the cost of construction is computed as follows:

   $________Operating Income B.I.T. x factor of. ______ = $________Credit toward construction costs.

   The customer(s) desiring service must advance the balance of the cost of construction.

   c. Computation of Customer Aid in Construction

   (i) Total Construction Cost.................... $...........

   (ii) Credit Towards Construction................ $...........

   (iii) Customer Aid-in-Construction................$...........

SECTION 9
LINE EXTENSIONS
(continued)

F. Construction / Facilities Related Income Taxes

Any federal, state or local income taxes resulting from the receipt of a contribution or advance in aid of construction in compliance with this rule is the responsibility of the Company and will be recorded as a deferred tax asset and reflected in the Company's rate base for ratemaking purposes.

However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the company's authorized rate of return.

EXHIBIT
tabbies
UNSE-58
Admitted

UNISOURCE ENERGY CORPORATION AND SUBSIDIARIES
OFFICER AND DIRECTOR LIST
(effective 8-24-07)

A. HOLDING COMPANY

UNISOURCE ENERGY CORPORATION

Officers:

James S. Pignatelli	President and Chief Executive Officer
Michael J. DeConcini	Senior Vice President and Chief Operating Officer, Transmission & Distribution
Raymond S. Heyman	Senior Vice President and General Counsel
Kevin P. Larson	Senior Vice President, Chief Financial Officer and Treasurer
Thomas N. Hansen	Vice President-Environmental Services, Conservation and Renewable Energy
Steven W. Lynn	Vice President, Communications and Government Relations
Karen G. Kissinger	Vice President, Controller and Chief Compliance Officer
Kentton C. Grant	Vice President, Finance & Rates
Arie Hoekstra	Vice President, Generation
David G. Hutchens	Vice President, Wholesale Energy
Thomas A. McKenna	Vice President, Engineering
Catherine E. Ries	Vice President, Human Resources
Linda H. Kennedy	Corporate Secretary
Assistant Officers:	
Carl W. Dabelstein	Assistant Treasurer
Michelle Livengood	Assistant Secretary

Directors:

James S. Pignatelli, Chairman
Lawrence J. Aldrich
Barbara M. Baumann
Larry W. Bickle
Elizabeth T. Bilby
Harold W. Burlingame
John L. Carter, Lead Dir.
Robert A. Elliott
Daniel W. L. Fessler
Kenneth Handy
Warren Y. Jobe
Joaquin Ruiz

UNISOURCE ENERGY DEVELOPMENT COMPANY

Officers:

James S. Pignatelli	President
Michael J. DeConcini	Vice President
Thomas A. McKenna	Vice President
C. David Lamoreaux	Secretary
Kevin P. Larson	Treasurer
Assistant Officers:	
Raymond S. Heyman	Assistant Secretary
Carl W. Dabelstein	Assistant Treasurer

Directors:

James S. Pignatelli
Michael J. DeConcini
Raymond S. Heyman

UNISOURCE ENERGY CORPORATION AND SUBSIDIARIES
OFFICER AND DIRECTOR LIST
(effective 8-24-07)

B. UTILITY SUBSIDIARIES

UNISOURCE ENERGY SERVICES, INC.

Officers:

James S. Pignatelli	President
Raymond S. Heyman	Senior Vice President and General Counsel
Kevin P. Larson	Vice President and Treasurer
Karen G. Kissinger	Vice President and Controller
David G. Hutchens	Vice President (Gas)
Thomas A. McKenna	Vice President (Electric)
Gary A. Smith	Vice President and General Manager
Thomas J. Ferry	Vice President and General Manager
Michelle Livengood	Secretary

Assistant Officers:

Carl W. Dabelstein	Asst. Treasurer
Linda H. Kennedy	Asst. Secretary
Roxana Ashurst	Asst. Secretary

Directors:
James S. Pignatelli
Kenneth Handy
Lawrence J Aldrich
Barbara M. Baumann
Larry W. Bickle
Elizabeth T. Bilby
Harold W. Burlingame
John L. Carter
Robert A. Elliott
Daniel. W.L. Fessler
Warren Y Jobe
Joaquin Ruiz

UNS ELECTRIC, INC. (formed 4-14-03)
Subsidiary of UniSource Energy Services, Inc.

Officers:

James S. Pignatelli	President
Raymond S. Heyman	Vice President and Secretary
Kevin P. Larson	Vice President and Treasurer
Karen G. Kissinger	Vice President and Controller
Thomas A. McKenna	Vice President
David G. Hutchens	Vice President
Thomas J. Ferry	Vice President and General Manager

Assistant Officers:

Linda H. Kennedy	Asst. Secretary
Carl W. Dabelstein	Asst. Treasurer
Roxana Ashurst	Asst. Secretary

Directors:
James S. Pignatelli
Michael J. DeConcini
Raymond S. Heyman

Summary of MARC Training Program Dates
(Management Associated Results Company, Inc.)

EXHIBIT
UNSE-59
Admitted

Completed training:

- Full three-day program:
    - February 28, March 1, & 2, 2005 – Tucson, Arizona
    - November 1, 2, & 3, 2005 – Kingman, Arizona
    - November 8, 9, & 10, 2005 – Flagstaff, Arizona

    - March 7, 8, & 9, 2006 – Show Low, Arizona
    - May 9, 10, & 11, 2006 – Flagstaff, Arizona

    - January 9, 10, & 11, 2007 – Flagstaff, Arizona
    - April 17, 18 & 19, 2007 – Tucson, Arizona

Proposed training is scheduled as follows:

- Full three-day program:
    - February 12, 13, & 14, 2008 – Site to be determined (probably Flagstaff)
    - 2010 – Tucson, Arizona (date TBD)

- One-day refresher training:
    - September 9 & 10, 2008 – Kingman, Arizona
    - September 11 & 12, 2008 – Flagstaff, Arizona
    - 2008 and 2009 – Tucson, Arizona (dates TBD)

Classes included employees from UNS Electric, Inc. (Mohave & Santa Cruz), UNS Gas, Inc. and Tucson Electric Power Company.

UNS Electric

Transaction Detail

All Sources

&GL Period Name, Co: 033mpany, &Account, &Subaccount, Co: 033st Center, &Task, &Expenditure Type, &Project Number, &Location, &Activity, &Business Center, &Cash Type, &Service Product Code, FERC Account: 0923

Co: 033	Vendor Name: MARC INC	Query Source: Payables

GL Period	Acct	Project	Sub A	Task Number	Gl JE Name	DR	CR	Net Amount	Ferc Account
DEC-05	52100	UNSE061	0000	E610930	Purchase Invoices USD		676.44	<676.44>	0923
DEC-05	52100	UNSE061	0000	E610930	Purchase Invoices USD	1,934.46		1,934.46	0923
DEC-05	52100	UNSE064	0000	E640930	Purchase Invoices USD		112.74	<112.74>	0923
DEC-05	52100	UNSE064	0000	E640930	Purchase Invoices USD	807.06		807.06	0923
DEC-05	52100	UNSE065	0000	E650930	Purchase Invoices USD		563.70	<563.70>	0923
DEC-05	52100	UNSE065	0000	E650930	Purchase Invoices USD	7,524.78		7,524.78	0923
JAN-06	52100	UNSE061	0000	E610930	Purchase Invoices USD	1,797.86		1,797.86	0923
JAN-06	52100	UNSE064	0000	E640930	Purchase Invoices USD	359.58		359.58	0923
JAN-06	52100	UNSE065	0000	E650930	Purchase Invoices USD	1,797.86		1,797.86	0923
FEB-06	52100	UNSE061	0000	E610930	Purchase Invoices USD		1,258.02	<1,258.02>	0923
FEB-06	52100	UNSE061	0000	E610930	Purchase Invoices USD	1,258.02		1,258.02	0923
FEB-06	52100	UNSE064	0000	E640930	Purchase Invoices USD		694.32	<694.32>	0923
FEB-06	52100	UNSE064	0000	E640930	Purchase Invoices USD	694.32		694.32	0923
FEB-06	52100	UNSE065	0000	E650930	Purchase Invoices USD		6,961.08	<6,961.08>	0923
FEB-06	52100	UNSE065	0000	E650930	Purchase Invoices USD	6,961.08		6,961.08	0923
DEC-06	52020	UNSE060	0000	E600923	Purchase Invoices USD	51.92		51.92	0923
DEC-06	52100	UNSE060	0000	E600923	Purchase Invoices USD		51.92	<51.92>	0923
DEC-06	52100	UNSE060	0000	E600923	Purchase Invoices USD	1,005.66		1,005.66	0923
DEC-06	52020	UNSE061	0000	E610923	Purchase Invoices USD	103.84		103.84	0923
DEC-06	52100	UNSE061	0000	E610923	Purchase Invoices USD		103.84	<103.84>	0923
DEC-06	52100	UNSE061	0000	E610923	Purchase Invoices USD	2,751.18		2,751.18	0923
DEC-06	52020	UNSE062	0000	E620923	Purchase Invoices USD	103.84		103.84	0923
DEC-06	52100	UNSE062	0000	E620923	Purchase Invoices USD		103.84	<103.84>	0923
DEC-06	52100	UNSE062	0000	E620923	Purchase Invoices USD	7,249.80		7,249.80	0923
DEC-06	52020	UNSE064	0000	E640923	Purchase Invoices USD	25.96		25.96	0923
DEC-06	52100	UNSE064	0000	E640923	Purchase Invoices USD		25.96	<25.96>	0923
DEC-06	52100	UNSE064	0000	E640923	Purchase Invoices USD	901.86		901.86	0923
JAN-07	52020	UNSE060	0000	E600930	Purchase Invoices USD	389.48		389.48	0923
FEB-07	52020	UNSE061	0000	E610923	Purchase Invoices USD	1,109.35		1,109.35	0923
FEB-07	52020	UNSE064	0000	E640923	Purchase Invoices USD	1,109.35		1,109.35	0923
Total						37,937.26	10,551.86	27,385.40	

EXHIBIT
RUCO-1
Admitted

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

TEST YEAR PLANT SCHEDULES - CONT'D
PORTION OF YEAR FROM AUGUST 11 ENDED DECEMBER 31, 2003

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) COMPANY DATA AS PROVIDED: GPIS 8/11/2003 FERC 1 - 2003	(B) GPIS 12/31/2003 FERC 1 - 2003	(C) ACC. DEP. 8/11/2003 RUCO DR 2.10	(D) AUTHORIZED DEP. RATES RUCO DR 1.09	(E) CALCULATION OF ACC. DEP. BALANCE 12/31/2003: PRO RATED FOR PARTIAL YEAR (08/11 TO 12/31/03)	(F) ACCRUAL DEPRECIATION (B) X (D) X (E)	(G) ACCUMULATED DEPRECIATION (C) + (F)	(H) ACC. DEP. CO. BOOK VALUE AS OF 12/31/03 RUCO DR 2.10	(I) UNDERSTATED ACC. DEP. (G - (H)
		Intangible:									
1	302	Franchises & Consents	$ 11,908	$ 11,908	$ -	0.00%	0.3890	$ -	$ -	$ -	$ -
2	303	Miscellaneous Intangible	5,364,321	5,364,321	(267,350)	0.00%	0.3890	-	(267,350)	(896,474)	629,124
3		Total Intangible Plant	$ 5,376,229	$ 5,376,229	$ (267,350)			$ -	$ (267,350)	$ (896,474)	$ 629,124
		Other Production									
4	340	Land & Rights	$ 765,874	$ 765,874	$ -	0.00%	0.3890	$ -	$ -	$ -	$ -
5	341	Structures & Improvements	619,244	619,244	(347,203)	1.38%	0.3890	(3,325)	(350,528)	(349,745)	(783)
6	342	Fuel Holders, Producers & Acc.	631,364	631,364	(84,539)	2.42%	0.3890	(5,944)	(90,483)	(87,714)	(2,769)
7	343	Prime Movers	8,684,079	8,684,079	(2,152,336)	2.34%	0.3890	(79,056)	(2,231,392)	(2,199,421)	(31,971)
8	344	Generators	2,309,132	2,309,132	(217,882)	0.67%	0.3890	(6,019)	(223,901)	(220,968)	(2,933)
9	345	Accessory Electric Equipment	1,685,197	1,685,197	(362,071)	2.20%	0.3890	(14,423)	(376,494)	(370,404)	(6,090)
10	346	Misc. Power Plant Equipment	493,979	493,979	(49,798)	1.87%	0.3890	(3,594)	(53,392)	(51,653)	(1,739)
11		Total Other Production	$ 15,188,868	$ 15,188,868	$ (3,213,829)			$ (112,361)	$ (3,326,190)	$ (3,279,905)	$ (46,285)
		Transmission :									
12	350	Land & Rights	$ 1,277,990	$ 1,277,990	$ -	0.00%	0.3890	$ -	$ -	$ -	$ -
13	352	Structures & Improvements	191,668	191,668	(130,927)	3.77%	0.3890	(2,811)	(133,738)	(132,985)	(753)
14	353	Station Equipment	16,025,096	16,025,096	(5,298,793)	2.92%	0.3890	(182,045)	(5,480,838)	(5,441,360)	(39,478)
15	354	Towers & Fixtures	521,825	521,825	(93,244)	2.87%	0.3890	(5,826)	(99,070)	(97,660)	(1,410)
16	355	Poles & Fixtures	10,659,976	10,659,976	(4,871,940)	5.77%	0.3890	(239,292)	(5,111,232)	(5,041,499)	(69,733)
17	356	Overhead Conductors & Devices	10,334,150	10,334,150	(3,587,560)	2.71%	0.3890	(108,953)	(3,696,513)	(3,658,297)	(38,216)
18	359	Roads & Trails	183,860	183,860	(64,417)	2.01%	0.3890	(1,438)	(65,855)	(65,353)	(502)
19		Total Transmission Plant	$ 39,194,566	$ 39,194,566	$ (14,046,881)			$ (540,365)	$ (14,587,246)	$ (14,437,154)	$ (150,092)
		Distribution:									
20	360	Land & Rights	$ 1,166,611	$ 1,166,611	$ -	0.00%	0.3890	$ -	$ -	$ -	$ -
21	361	Structures & Improvements	3,398,247	3,398,247	(564,317)	3.20%	0.3890	(42,306)	(606,623)	(587,645)	(18,978)
22	362	Station Equipment	28,581,801	28,581,801	(11,075,977)	4.82%	0.3890	(535,960)	(11,611,937)	(11,434,870)	(177,067)
23	364	Poles, Towers & Fixtures	69,845,361	69,845,361	(28,732,536)	4.23%	0.3890	(1,149,406)	(29,881,942)	(29,525,606)	(356,336)
24	365	Overhead Conductors & Devices	42,881,347	42,881,347	(18,360,376)	4.36%	0.3890	(727,362)	(19,087,738)	(18,856,255)	(231,483)
25	366	Underground Conduit	11,059,212	11,059,212	(2,888,173)	4.28%	0.3890	(184,146)	(3,072,319)	(2,985,408)	(86,911)
26	367	UG Conductors & Devices	17,365,966	17,365,966	(7,260,867)	5.36%	0.3890	(362,126)	(7,622,993)	(7,523,560)	(99,433)
27	368	Line Transformers	35,295,314	35,295,314	(17,308,671)	4.93%	0.3890	(676,954)	(17,985,625)	(17,814,301)	(171,324)
28	369	Services	10,611,508	10,611,508	(3,331,419)	4.23%	0.3890	(174,628)	(3,506,047)	(3,441,660)	(64,387)
29	370	Meters	7,791,750	7,791,750	(2,238,651)	3.25%	0.3890	(98,518)	(2,337,169)	(2,299,980)	(37,189)
30	373	Street Lights & Signal Systems	3,070,678	3,070,678	(895,369)	4.55%	0.3890	(54,355)	(949,724)	(929,027)	(20,697)
31		Total Distribution Plant	$ 231,067,795	$ 231,067,795	$ (92,656,356)			$ (4,005,760)	$ (96,662,116)	$ (95,398,312)	$ (1,263,804)
		General:									
32	389	Land & Rights	$ 57,580	$ 57,580	$ -	0.00%	0.3890	$ -	$ -	$ -	$ -
33	390	Structures & Improvements	1,813,346	1,813,346	(669,439)	2.89%	0.3890	(20,388)	(689,827)	(676,796)	(13,031)
34	391	Office Furniture & Equipment	2,310,217	2,310,217	(897,271)	3.72%	0.3890	(33,434)	(930,705)	(279,127)	(651,578)
35	392	Transportation Equipment	7,425,475	7,425,475	(7,204,543)	25.00%	0.3890	(722,204)	(7,926,747)	(6,932,672)	(994,075)
36	393	Stores Equipment	122,871	122,871	(48,417)	2.62%	0.3890	(1,252)	(49,669)	(50,167)	498
37	394	Tools, Shop And Garage Equip.	2,339,362	2,339,362	(295,739)	3.02%	0.3890	(27,485)	(323,224)	(798,234)	475,010
38	395	Laboratory Equipment	808,108	808,108	(161,045)	2.41%	0.3890	(7,577)	(168,622)	(155,792)	(12,830)
39	396	Power Operated Equipment	968,258	968,258	(399,013)	3.33%	0.3890	(12,544)	(411,557)	(666,063)	254,506
40	397	Communication Equipment	1,046,456	1,046,456	(218,468)	4.13%	0.3890	(16,814)	(235,282)	(250,998)	15,716
41	398	Miscellaneous Equipment	114,643	114,643	(82,053)	5.45%	0.3890	(2,431)	(84,484)	(76,606)	(7,878)
42		Total General Plant	$ 17,006,316	$ 17,006,316	$ (9,975,988)			$ (844,129)	(10,820,117)	$ (9,886,455)	$ (933,662)
		Rounding	$ (1)	$ (1)							
43		TOTAL PLANT	$ 307,833,774	$ 307,833,774	$ (120,160,404)			$ (5,502,615)	(125,663,019)	$ (123,898,300)	$ (1,764,719)
44		UNDERSTATED ACCUMULATED DEPRECIATION									$ (1,764,719)

References:
Columns (A) (B) (C) (D) (H): Company Response To RUCO Data Requests
Column (E): 142 Days Of The Partial Year From 08/11/03 To 12/31/03) / 365 Days Of A Full Year
Column (F): Column (B) X Column (D) X Column (E)
Column (G): Column (C) + Column (F)
Column (I): Column (G) - Column (H)

UNS Electric
Response to RUCO D.R. 2.10 - Attachment A

	Accumulated Depreciation	
Description	Per Books Balance at 08/11/03	Per Books Balance at 12/31/03
Intangible Plant:		
Acct 302 Franchises & Consents	-	-
Acct 303 Misc. Intangible Plant	(267,350)	(896,474)
	(267,350)	(896,474)
Other Production Plant:		
Acct 340 Land & Land Rights	-	-
Acct 341 Structures & Improvements	(347,203)	(349,745)
Acct 342 Fuel Holders, Producers & Accessories	(84,539)	(87,714)
Acct 343 Prime Movers	(2,152,336)	(2,199,421)
Acct 344 Generators	(217,882)	(220,968)
Acct 345 Accessory Electric Equipment	(362,071)	(370,404)
Acct 346 Misc. Power Plant Equip.	(49,798)	(51,653)
	(3,213,829)	(3,279,905)
Transmission Plant:		
Acct 350 Land & Land Rights	-	-
Acct 352 Structures & Improvements	(130,927)	(132,985)
Acct 353 Station Equipment	(5,298,793)	(5,441,360)
Acct 354 Towers & Fixtures	(93,244)	(97,660)
Acct 355 Poles & Fixtures	(4,871,940)	(5,041,499)
Acct 356 Overhead Conductors & Devices	(3,587,560)	(3,658,297)
Acct 358 Underground Conductors & Devices	(12,667)	-
Acct 359 Roads & Trails	(64,417)	(65,353)
	(14,059,548)	(14,437,154)

UNS Electric
Response to RUCO D.R. 2.10 - Attachment A

	Accumulated Depreciation	
Description	Per Books Balance at 08/11/03	Per Books Balance at 12/31/03
Distribution Plant:		
Acct 360 Land & Land Rights	-	-
Acct 361 Structures & Improvements	(564,317)	(587,645)
Acct 362 Station Equipment	(11,075,977)	(11,434,870)
Acct 364 Poles, Towers & Fixtures	(28,732,536)	(29,525,606)
Acct 365 Overhead Conductors & Devices	(18,360,376)	(18,856,255)
Acct 366 Underground Conduit	(2,875,506)	(2,985,408)
Acct 367 Underground Conductors & Devices	(7,260,867)	(7,523,560)
Acct 368 Line Transformers	(17,308,671)	(17,814,301)
Acct 369 Meters	(3,331,419)	(3,441,660)
Acct 370 Services	(2,238,651)	(2,299,980)
Acct 373 Street Lighting & Signal Systems	(895,369)	(929,027)
	(92,643,689)	(95,398,312)
General Plant:		
Acct 389 Land & Land Rights	-	-
Acct 390 Structures & Improvements	(669,439)	(676,796)
Acct 391 Office Furniture & Equip.	(897,271)	(279,127)
Acct 392 Transportation Equipment	(7,204,543)	(6,932,672)
Acct 393 Stores Equipment	(48,417)	(50,167)
Acct 394 Tools, Shop & Garage Equip.	(295,739)	(798,234)
Acct 395 Laboratory Equipment	(161,045)	(155,792)
Acct 396 Power Operated Equipment	(399,013)	(666,063)
Acct 397 Communications Equipment	(218,468)	(250,998)
Acct 398 Misc. Equipment	(82,053)	(76,606)
	(9,975,988)	(9,886,455)
Total Plant In Service	(120,160,404)	(123,898,300)

F.E.R.C. Acct. No.	Depreciation Rate Mohave	Santa Cruz
302	-	-
303 -		
Software	20.00	20.00
WAPA Comm. Line (a)	4.13	-
WAPA Switchyard (b)	2.92	
311	2.50	2.50
316	-	2.88
340	-	-
341	-	1.38
342	-	2.42
343	-	2.34
344	-	0.67
345	-	2.20
346	-	1.87
350	-	-
352	3.77	3.77
353	2.92	2.92
354	2.87	4.32
355	5.77	5.77
356	2.71	2.71
358	4.36	-
359	2.01	2.01
360	-	-
361	3.20	3.20
362	4.82	4.82
364	4.23	4.23
365	4.36	4.36
366	4.28	4.28
367	5.36	5.36
368	4.93	4.93
369	4.23	4.23
370	3.25	3.25
373	4.55	4.55
389	-	-
390	2.89	2.89
391 -		
Office Furniture & Equip.	3.72	3.72
Computer Equipment	20.00	20.00
392 -		
Vehicles < $100K	25.00	25.00
Vehicles > $100K	12.50	12.50
393	2.62	2.62
394	3.02	3.02
395	2.41	2.41
396	3.33	3.33
397	4.13	4.13
398	5.45	5.45

(a) WAPA Fiber Optic Communictions Line - Depreciated at same rate as Acct.No. 397, Communications Equipment.

(b) WAPA Switchyard - Depreciated at same rate as Acct. 353, Station Equipment.

EXHIBIT
RUCO-2
Admin. Notice

ORIGINAL

NEW APPLICATION

RECEIVED

BEFORE THE ARIZONA CORPORATION COMMISSION

2007 SEP -6 P 1:39

AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
DOCKETED
SEP 06 2007
DOCKETED BY

E-04204A-07-0512

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF UNS ELECTRIC, INC.'S PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE BANK BALANCE.

DOCKET NO. E-04204A-07-____

UNS ELECTRIC'S PPFAC BANK BALANCE NOTIFICATION

UNS Electric, Inc. ("UNS Electric"), through undersigned counsel, respectfully submits this notification that its current Purchased Power and Fuel Adjustment Clause ("PPFAC") bank balance is in excess of the $2,600,000 threshold set forth in Decision No. 62094 (November 19, 1999). However, UNS Electric does not believe a PPFAC rate adjustment is necessary at this time. In support hereof, UNS Electric states as follows:

I. UNS ELECTRIC'S NOTICE REGARDING PPFAC BANK BALANCE.

Decision No. 62094 states:

> When the absolute value of the PPFAC bank balance exceeds the threshold amount ($2,600,000), Citizens would either:
>
> a. File for a PPFAC rate adjustment within 45 days of determining that the threshold has been exceeded: or
>
> b. Contact Staff to discuss why a PPFAC rate adjustment is not necessary at this time.

UNS Electric's most-recently completed monthly informational filing indicates that the over-collection threshold has been exceeded. Specifically, UNS Electric's July 23, 2007 monthly informational filing indicated that a bank balance of $2,870,472 existed at the end of April 2007, exceeding the current $2,600,000 threshold.

II. UNS ELECTRIC'S RECOMMENDATION THAT THE PPFAC RATE REMAIN UNCHANGED.

Despite the over-collected balance, UNS Electric believes a PPFAC rate adjustment is not necessary at this time and instead should be addressed in the recently filed UNS Electric rate case (Docket No. E-04204A-06-0783; the "UNS Electric Rate Case"). In the UNS Electric Rate Case, Commission Staff and the Company have proposed an entirely different PPFAC mechanism based on a forward forecast of fuel and purchased power costs.

III. CONCLUSION.

UNS Electric believes it is in the public interest to keep the PPFAC rate unchanged and address the over-collected bank balance threshold in the UNS Electric rate case.

WHEREFORE, for all the forgoing reasons, UNS Electric requests that its PPFAC rate remain unchanged at this time.

RESPECTFULLY SUBMITTED this 6th day of September 2007.

UNS Electric, Inc.

By Michelle Livengood
Michelle Livengood
One South Church Avenue
Tucson, Arizona 85702

Attorney for UNS Electric, Inc.

Original and 13 copies of the foregoing
filed this 6th day of September 2007 with:

Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007

Copy of the foregoing hand-delivered/mailed
this 6th day of September 2007

Chairman Mike Gleason
Arizona Corporation Commission

1200 West Washington Street
Phoenix, Arizona 85007

Commissioner William A. Mundell
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Jeff Hatch-Miller
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Commissioner Gary Pierce
Arizona Corporation Commission
1200 West Washington Street
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Lyn A. Farmer, Esq.
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Hearing Division
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Christopher C. Kempley, Esq.
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Arizona Corporation Commission
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Ernest G. Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

David Couture
Director, Regulatory Services
Tucson Electric Power Company
P.O. Box 711
Tucson, AZ 85702-0711

By: Mary Ippolito

EXHIBIT
RUCO 3
admitted

UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 25, 2007

STF 3.81 Employee Benefits. For the test year, list all payments made for employee gifts, employee awards, employee luncheons and dinners, employee picnics, parties, social events and all other similar items. For each, list the dollar amount paid, the payee, the account charged and state the purpose.

SUPPLEMENTAL RESPONSE: Please see the list below:

RUCO-3

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 25, 2007**

DATE	PAYEE	DESCRIPTION OF EXPENSE	FERC	PYMT AMOUNT
07/29/2005	Shamrock Foods, Co	Employee Retirement	930	$280.04
07/2005	Arcman	Employee Retirement	930	$250.00
07/01/2005	Home Depot	Employee Appreciation	921	$50.00
07/01/2005	Dambar	Employee Appreciation	921	$100.00
10/14/2005	Soto's	Going away lunch for Russ Vallejo	930	$40.00
11/10/2005	Valerie Banta	Decorations	921	$400.00
11/11/2005	Palo Duro	Employee appreciation dinner deposit	930	$300.00
11/30/2005	Fog Band	Music for employee appreciation dinner	921	$250.00
11/30/2005	Dunton Sign	Room Rental	921	$338.00
11/2005	Wal-Mart	Decorations	921	$9.40
11/2005	Pier One	Decorations	921	$120.68
11/2005	Michaels	Decorations	921	$178.63
11/2005	Walgreens	Photos	921	$205.30
12/05/2005	K-Mart	Decorations	921	$10.76
12/14/2005	Michael Gual Catering	Food	921	$1,690.00
12/19/2005	Palo Duro	Employee appreciation dinner	921	$1,381.73
12/19/2005	Palo Duro	Employee appreciation dinner	921	$1,300.00
12/2005	Party City	Decorations	921	$14.92
12/2005	Wal-Mart	Decorations	921	$14.10
12/2005	Wal-Mart	Decorations	921	$9.40
12/2005	Ramada Inn	Employee Appreciation dinner; Food & Room	921	$3,501.85
12/2005	Mandarin Orchid	Flowers for 'Get Well' or 'Funeral'	921	$49.14
12/2005	Mandarin Orchid	Flowers for 'Get Well' or 'Funeral'	921	$49.14
12/2005	Mandarin Orchid	Flowers for 'Get Well' or 'Funeral'	903	$81.57
12/2005	Safeway	Flowers for 'Get Well' or 'Funeral'	903	$14.75
12/2005	Glazier's Food Town	Flowers for 'Get Well' or 'Funeral'	588	$107.75
03/03/2006	Ole Pueblo Grill	25th Anniversary Employee Recognition	930	$40.43
03/08/2006	Dambar	Employee Appreciation	930	$50.00
03/19/2006	Shagru's	Gift Certificate for Safety Empl of the year	930	$50.00
03/23/2006	Home Depot	Gift Certificate for Safety Empl of the year	930	$100.00
03/23/2006	Signs	Plaque for Safety Empl of the year	930	$28.93
03/31/2006	Safeway	Empl Retirement food	903	$47.97
03/2006	Mandarin Orchid	Flowers for 'Get Well' or 'Funeral'	903	$64.71
04/20/2006	Arcman	Employee Retirement gift	921	$323.70
04/26/2006	Red Robin	Employee Appreciation	893	$53.89
05/11/2006	Chilis	Employee Appreciation	891	$22.92
06/07/2006	Red Robin	Employee Appreciation	901	$26.47
06/29/2006	Chilis	Employee Appreciation	891	$49.42
06/28/2006	Wal-Mart	Employee Appreciation BBQ for 4th of July	921	$121.08
06/30/2006	Wal-Mart	Employee Appreciation BBQ for 4th of July	921	$11.34

**UNS ELECTRIC, INC.'S RESPONSES TO
STAFF'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 25, 2007**

RESPONDENT: Teri Rice

WITNESS: Dallas Dukes

EXHIBIT
RUCO-4
Admitted

UNS ELECTRIC, INC.'S RESPONSES TO
RUCO'S SECOND SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 14, 2007

2.11 Operating Income – Please provide test-year transaction activity for all journal entries in the following FERC accounts:

a. 921 – A & G Expense – Office Supplies $497,037;
b. 923 – A & G Expense – Outside Services Employed $2,750,908; and
c. 930 – A & G Expense – Misc. General Expense $1,001,956.

Please provide the information in the same format as the UNS Gas response to RUCO data request 2.10.

RESPONSE: Please see RUCO 2.11 (Operating Income) on the enclosed CD for spreadsheet files containing requested information. The Excel file, RUCO 2.11 (Operating Income), on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Mina Briggs

WITNESS: Dallas Dukes

RUCO-4

UNS ELECTRIC, INC.'s RESPONSES TO
RUCO'S FIFTH SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
June 18, 2007

5.01 Operating Income - With reference to the Company's workpapers in response to RUCO data request 2.11, please review attached Exhibit B which itemizes expenses filed in that response, which RUCO intends to remove from the Company's filing as unnecessary/inappropriate costs for the provisioning of electric service to UNS customers.

Please refer to the column marked "RUCO's Comments" for the rationale behind this adjustment.

Examples of criteria (but not limited to) used in making the determination to remove these expenses from the test-year operating expense are:

I. What essential customer benefits for the provisioning of electric service does this expense provide the ratepayers?

II. Are these types of expenditures repetitive and typical to UNS's operation, or are they unique and non-recurring?

III. Was this expense associated with capital projects, lobbying, etc.?

IV. How often has the Company incurred similar expenses in the last three years?

V. Is this a reasonable level of expense for service rendered?

VI. Is this a necessary expense for the provisioning of electric service to the ratepayers?

RESPONSE: UNS Electric, Inc. ("UNS Electric" or the "Company") has reviewed RUCO's Exhibit B and has highlighted those line items that should be removed. The remaining expenses should be considered routine and reasonable as they are related to providing service to our customers or training employees. Please see RUCO 5.01 (Revised Exhibit B) on the enclosed CD for an explanation of Company expenses. The Excel file on the enclosed CD is not identified by Bates numbers.

RESPONDENT: Teri Rice

WITNESS: Thomas Ferry

UNS Electric Corporation
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	or e N	DR	CR	Net Amount		RUCO'S COMMENT	UNSE COMMENT
JAN-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462		75.85		75.85	R	Excessive	Business meals
JAN-06	0921	Projects	PVS Net - Procard Charges		FOOD CITY #108 STP		14.97		14.97	R	Inappropriate	Travel & Training
JAN-06	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO		98.28		98.28	R	Inappropriate	Flowers for employee family funeral
JAN-06	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL		112.80		112.80	R	Excessive	Travel & Training CC& B Team Mtg
JAN-06	0921	Projects	PVS Net - Procard Charges		KINGMAN CHAMBER OF COM		357.50		357.50	R	Sponsorship	Dues
JAN-06	0921	Payables		Purchase Invoice	KINGMAN ROTARY CLUB	011	133.00		133.00	R	Sponsorship	Dues
JAN-06	0921	Projects	PVS Net - Procard Charges		RAMADA EXPRESS CSN CGE		150.00		150.00	R	Questionable Expense	3 employee appreciation
JAN-06	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT #8488		52.39		52.39	R	Inappropriate	Office Lobby Mini Blinds
JAN-06	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		43.46		43.46	R	Out-Of-State Expense	Located in Lake Havasu Travel & Training
JAN-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00052Q39		37.63		37.63	R	Inappropriate	Business Office Expense
JAN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2		36.03		36.03	R	Inappropriate	Office Supplies
JAN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2		538.88		538.88	R	Inappropriate	Repl 5 year old Digital Carmera-Office/Field use
JAN-06	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2		54.67		54.67	R	Inappropriate	Office Supplies
JAN-06	0921	Projects	PVS Net - Procard Charges		WOODLANDS PLAZA HOTEL		71.58		71.58	R	Out-Of-State Expense	Located in Flagstaff Travel & Training
FEB-06	0921	Projects	PVS Net - Procard Charges		AZ TOWN HALL		50.00		50.00	R	Sponsorship	agree
FEB-06	0921	Projects	PVS Net - Procard Charges		BRUEGGER'S BAGELS -Q51		2.79		2.79	R	Inappropriate	Travel & Training
FEB-06	0921	Projects	PVS Net - Procard Charges		CARLTON CARDS #0408		47.97		47 97	R	Inappropriate	Office Supplies
FEB-06	0921	Projects	PVS Net - Procard Charges		CHA-BONES		77.61		77.61	R	Excessive	Business meals 3 separate receipts
FEB-06	0921	Projects	PVS Net - Procard Charges		GREAT LAK 64615481193795		127.99		127.99	R	Questionable Expense	Travel Expense
FEB-06	0921	Projects	PVS Net - Procard Charges		H.L.A FRONT DESK #1		85.89		85.89	R	Questionable Expense	Travel Expense
FEB-06	0921	Projects	PVS Net - Procard Charges		JAVELINA CANTINA		50.61		50.61	R	Excessive	Business meals 2 separate receipts
FEB-06	0921	Payables		Purchase Invoice	KINGMAN MOHAVE LIONS CLUB	144	60.00		60.00	R	Sponsorship	Dues
FEB-06	0921	Payables		Purchase Invoice	KINGMAN ROUTE 66 ROTARY CLUB	020	250.00		250.00	R	Sponsorship	Dues
FEB-06	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO		12.00		12.00	R	Out-Of-State Expense	Travel
FEB-06	0921	Projects	PVS Net - Procard Charges		MOHAVE COMMUNITY C		35.00		35.00	R	Sponsorship	Dues
FEB-06	0921	Projects	PVS Net - Procard Charges		MONTI'S LA CASA VIEJA		65.74		65.74	R	Excessive	Training two receipts
FEB-06	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT 403		194.09		194.09	R	Inappropriate	Purchase window Blinds for Office & Crew Rooms
FEB-06	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		21.25		21.25	R	Out-Of-State Expense	Located in Lake Havasu Employee Meals
FEB-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00076Q39		4.08		4.08	R	Inappropriate	Office Supplies
FEB-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2		13.97		13.97	R	Inappropriate	Office Supplies
FEB-06	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2		80.46		80.46	R	Inappropriate	Office Supplies
MAR-06	0921	Projects	PVS Net - Procard Charges		AZ REPUBLIC SUBSCRIPTI		200.20		200.20	R	Inappropriate	Newspaper Subscription
MAR-06	0921	Projects	PVS Net - Procard Charges		BARNES & NOBLE #2962		27.02		27.02	R	Inappropriate	Office Supplies
MAR-06	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE		70.18		70.18	R	Excessive	Business meals, 3 employees
MAR-06	0921	Projects	PVS Net - Procard Charges		EL PALACIO OF KINGMAN		50.83		50.83	R	Excessive	Business meals
MAR-06	0921	Projects	PVS Net - Procard Charges		EMBASSY SUITES FLAGTIP		152.98		152.98	R	Questionable Expense	Travel & Training
MAR-06	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416		71.09		71.09	R	Inappropriate	Materials Purchased
MAR-06	0921	Projects	PVS Net - Procard Charges		JA STEAKHOUSE		80.60		80.60	R	Excessive	Business meals
MAR-06	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL		210.60		210.60	R	Excessive	Business meals
MAR-06	0921	Projects	PVS Net - Procard Charges		JAVELINA CANTINA		55.83		55.83	R	Excessive	Business meals
MAR-06	0921	Projects	PVS Net - Procard Charges		KINGMAN CHAMBER OF COM		30.00		30.00	R	Sponsorship	Dues
MAR-06	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE		26.44		26.44	R	Inappropriate	Business meals
MAR-06	0921	Projects	PVS Net - Procard Charges		MUDSHARK BREWING CO		27.23		27.23	R	Inappropriate	Business meals
MAR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00002162		4.64		4.64	R	Inappropriate	Meal expense
MAR-06	0921	Projects	PVS Net - Procard Charges		TERRIBLES #148		3.38		3.38	R	Out-Of-State Expense	Travel & Training in Havasu
MAR-06	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT #8488		98.70		98.70	R	Inappropriate	Office Supplies
MAR-06	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		31.04		31.04	R	Out-Of-State Expense	Business meals in Lake Havasu
MAR-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2		13.46		13.46	R	Inappropriate	Office Supplies
MAR-06	0921	Projects	PVS Net - Procard Charges		XEROX SUPPLY TEXAS		185.91		185.91	R	Questionable Expense	Office Supplies
APR-06	0921	Projects	PVS Net - Procard Charges		CHUYS MESQUITE BROILER		75.34		75.34	R	Excessive	Business meals
APR-06	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE		153.59		153.59	R	Excessive	Business meals, employee meetings
APR-06	0921	Projects	PVS Net - Procard Charges		ELKS LODGE #468		145.00		145.00	R	Sponsorship	Meeting Room Rental
APR-06	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU CITY-CUST		50.00		50.00	R	Sponsorship	Permit & License
APR-06	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE		42.16		42.16	R	Out-Of-State Expense	Kingman Business meals
APR-06	0921	Projects	PVS Net - Procard Charges		RED ROBIN		74.65		74.65	R	Excessive	Business meals
APR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879		21.30		21.30	R	Inappropriate	Business meals
APR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020289		25.27		25.27	R	Inappropriate	Business meals
APR-06	0921	Projects	PVS Net - Procard Charges		SHUGRUES RESTAURANT		50.00		50.00	R	Excessive	Employee Recognition
APR-06	0921	Projects	PVS Net - Procard Charges		STARBUCKS USA 00069Q48		4.04		4.04	R	Inappropriate	Business meals

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	[illegible]e N	DR	CR	Net Amount		RUCO'S COMMENT	UNSE COMMENT
AUG-05	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU		126.52		126.52	R	Excessive	Business meals
AUG-05	0921	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6		42.84		42.84	R	Inappropriate	Employee meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		SUBWAY 16276		70.86		70.86	R	Excessive	Employee Appreciation BBQ
AUG-05	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT #8488		14.95		14.95	R	Inappropriate	Materials Purchased
AUG-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		18.31		18.31	R	Out-Of-State Expense	Located in Lake Havasu Business meals
AUG-05	0921	Projects	PVS Net - Procard Charges		WALGREEN 00035Q39		17.27		17.27	R	Inappropriate	Office Supplies
AUG-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2		196.19		196.19	R	Inappropriate	Office Supplies
AUG-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2		127.58		127.58	R	Inappropriate	Ice for Crews
AUG-05	0921	Projects	PVS Net - Procard Charges		BRUEGGERS BAGEL BAKERY		7.62		7.62	R	Inappropriate	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		CHA-BONES		70.40		70.40	R	Excessive	Employee Meas
SEP-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05540		11.93		11.93	R	Inappropriate	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE		56.97		56.97	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		EMBASSY SUITES FLAGTIP		339.03		339.03	R	Questionable Expense	Employee Travel
SEP-05	0921	Projects	PVS Net - Procard Charges		ENOTECA PIZZARIA WINE		63.91		63.91	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET		33.00		33.00	R	Out-Of-State Expense	Travel Expense
SEP-05	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO		60.00		60.00	R	Inappropriate	Employee Flowers
SEP-05	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE		55.73		55.73	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		KINGMAN-CHILI'00010462		75.63		75.63	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU-CH00010496		41.79		41.79	R	Sponsorship	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		LK HAVASU CITY CHMBR		35.00		35.00	R	Sponsorship	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		NORZAGARAY FOOD MARKET		166.79		166.79	R	Inappropriate	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		OUTBACK #0315		76.73		76.73	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172		56.12		56.12	R	Inappropriate	Employee meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU		78.30		78.30	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		STARBUCKS USA 00088Q48		5.51		5.51	R	Inappropriate	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		TEQUILA CHARLIE'S		131.59		131.59	R	Excessive	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		TEXAS ROADHOUSE #2204		121.91		121.91	R	Out-Of-State Expense	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		THE GOOD STUFF		29.60		29.60	R	Questionable Expense	Business meals
SEP-05	0921	Projects	PVS Net - Procard Charges		THE OLIVE GARD00010959		50.32		50.32	R	Excessive	~~Business meals~~
SEP-05	0921	Projects	PVS Net - Procard Charges		USA CHARTER BUS		891.25		891.25	R	Inappropriate	Travel Expense
SEP-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2		34.65		34.65	R	Inappropriate	~~Office~~ Expenses
SEP-05	0921	Projects	PVS Net - Procard Charges		A FRAME OF MIND		38.83		38.83	R	Inappropriate	Employee Plaque
OCT-05	0921	Projects	PVS Net - Procard Charges		ALBERTSONS #967 S9H		23.45		23.45	R	Inappropriate	Employee meeting
OCT-05	0921	Projects	PVS Net - Procard Charges		BARLEY BROTHERS BREWER		40.13		40.13	R	Inappropriate	Business meals
OCT-05	0921	Projects	PVS Net - Procard Charges		BASHAS #116 SYW		22.67		22.67	R	Inappropriate	Employee meeting
OCT-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 01773		5.00		5.00	R	Inappropriate	Business meals
OCT-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE		108.79		108.79	R	Excessive	Business meals
OCT-05	0921	Projects	PVS Net - Procard Charges		DANONE WATERS OF NORTH		89.50		89.50	R	Inappropriate	Drinking Water
OCT-05	0921	Projects	PVS Net - Procard Charges		DIAMOND 1624 SHAMROCK		5.55		5.55	R	Inappropriate	Employee meeting
OCT-05	0921	Projects	PVS Net - Procard Charges		ELKS LODGE #468		120.00		120.00	R	Sponsorship	Meeting Rental
OCT-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET		29.00		29.00	R	Out-Of-State Expense	Travel Expense
OCT-05	0921	Projects	PVS Net - Procard Charges		G & E'S BORDER PRINT S		42.60		42.60	R	Questionable Expense	Office Supplies
OCT-05	0921	Projects	PVS Net - Procard Charges		GREAT LAK 84612472893255		101.50		101.50	R	Questionable Expense	Travel Expense
OCT-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416		200.00		200.00	R	Inappropriate	Employee Appreciation Awards
OCT-05	0921	Payables		Purchase Invoice	HUALAPAI TRIBE	11[illegible]	250.00		250.00	R	Sponsorship	Agree
OCT-05	0921	Projects	PVS Net - Procard Charges		OMNI HOTELS TUCSON RES		350.16		350.16	R	Excessive	Travel Expense
OCT-05	0921	Projects	PVS Net - Procard Charges		RUBY TUESDAY #4574		124.61		124.61	R	Excessive	Business meals
OCT-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172		27.38		27.38	R	Inappropriate	Employee meeting
OCT-05	0921	Projects	PVS Net - Procard Charges		SUNSET STN SUNST CAFE		16.93		16.93	R	Out-Of-State Expense	Business meals
OCT-05	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT 403		86.28		86.28	R	Inappropriate	Materials Purchased
OCT-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		50.96		50.96	R	Out-Of-State Expense	Located in Lake Havasu Business meals
OCT-05	0921	Projects	PVS Net - Procard Charges		BEER BOTTOM'S BISTRO		42.75		42.75	R	Inappropriate	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462		70.83		70.83	R	Excessive	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		CHINA BUFFET - LH		56.86		56.86	R	Excessive	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05923		2.98		2.98	R	Inappropriate	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		COLORADO BELLE F/B		10.76		10.76	R	Out-Of-State Expense	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE		121.69		121.69	R	Excessive	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET		27.00		27.00	R	Out-Of-State Expense	Travel Expense
NOV-05	0921	Projects	PVS Net - Procard Charges		GAYLORD TEXAN F&B		16.02		16.02	R	Out-Of-State Expense	Business meals training
NOV-05	0921	Projects	PVS Net - Procard Charges		HMS HOST-LAS-AIRPT#241		1.93		1.93	R	Out-Of-State Expense	Travel Expense
NOV-05	0921	Projects	PVS Net - Procard Charges		HMSHOST-LAS-AIRPT #008		10.75		10.75	R	Out-Of-State Expense	Travel Expense
NOV-05	0921	Projects	PVS Net - Procard Charges		LOVE AND WAR IN TEXAS		49.52		49.52	R	Out-Of-State Expense	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		MACARONI GR30100003012		94.49		94.49	R	Excessive	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE		23.86		23.86	R	Out-Of-State Expense	Business meals
NOV-05	0921	Payables		Purchase Invoice	PERFECTION ENTERTAINMENT	11[illegible]	350.00		350.00	R	Inappropriate	agree
NOV-05	0921	Projects	PVS Net - Procard Charges		PLN*NO REFUNDS		894.50		894.50	R	Questionable Expense	~~Travel Expense~~
NOV-05	0921	Projects	PVS Net - Procard Charges		QUINN FLAG		608.40		608.40	R	Inappropriate	Office and Warehouse Flags

6/19/2007

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	e N	DR	CR	Net Amount		RUCO'S COMMENT	UNSE COMMENT
APR-06	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT #0416		746.96		746.96	R	Inappropriate	Office BBQ
APR-06	0921	Projects	PVS Net - Procard Charges		ZIVAZ		51.43		51.43	R	Excessive	Business meals
MAY-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462		50.25		50.25	R	Excessive	Business meals
MAY-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI41600004168		50.33		50.33	R	Excessive	Business meals
MAY-06	0921	Projects	PVS Net - Procard Charges		G & E S BORDER PRINT S		71.74		71.74	R	Questionable Expense	Office Supplies
MAY-06	0921	Projects	PVS Net - Procard Charges		GOLDEN CORRAL 2465		53.19		53.19	R	Excessive	Business meals
MAY-06	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE		71.72		71.72	R	Excessive	Business meals
MAY-06	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU CHAMBER OF		15.00		15.00	R	Sponsorship	Dues
MAY-06	0921	Projects	PVS Net - Procard Charges		MUDSHARK BREWING CO		52.28		52.28	R	Inappropriate	Business meals
MAY-06	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		22.70		22.70	R	Out-Of-State Expense	Located in Lake Havasu Employee Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00076Q39		10.73		10.73	R	Inappropriate	Office Supplies
JUN-06	0921	Projects	PVS Net - Procard Charges		BASHA S 30 SYW		10.28		10.28	R	Inappropriate	Business meals
JUN-06	0921	Projects	PVS Net - Procard Charges		BASHAS #116 SYW		5.97		5.97	R	Inappropriate	Business meals
JUN-06	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05290 Q04		28.78		28.78	R	Inappropriate	Vehicle Fuel
JUN-06	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT		15.97		15.97	R	Inappropriate	Safety Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET		45.00		45.00	R	Out-Of-State Expense	Travel Expense
JUN-06	0921	Projects	PVS Net - Procard Charges		HMS HOST-LAS-AIRPT#241		3.01		3.01	R	Out-Of-State Expense	Travel Expense
JUN-06	0921	Projects	PVS Net - Procard Charges		MAD DOGS BAR & GRILL		27.28		27.28	R	Inappropriate	Business meals
JUN-06	0921	Payables		Purchase Invoice	MINKUS ADVERTISING SPECIALTIES	061	2,357.86		2,357.86	R	Inappropriate	agree
JUN-06	0921	Projects	PVS Net - Procard Charges		ORB*M57ZGF		901.20		901.20	R	Questionable Expense	agree
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00002SC9		25.61		25.61	R	Inappropriate	Employee meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018SC9		57.63		57.63	R	Inappropriate	Employee meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020SC9		11.88		11.88	R	Inappropriate	Business meals
JUN-06	0921	Projects	PVS Net - Procard Charges		SHORT STOP MINI MARKET		4.75		4.75	R	Inappropriate	Business meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SHUGRUES RESTAURANT		137.95		137.95	R	Excessive	Business meals HR related
JUN-06	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU		164.34		164.34	R	Excessive	Business meals
JUN-06	0921	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6		20.93		20.93	R	Inappropriate	Employee meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		TERRIBLES #148		14.37		14.37	R	Out-Of-State Expense	Located in Lake Havasu Employee meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1364		17.18		17.18	R	Inappropriate	Office Supplies
JUL-05	0921	Projects	PVS Net - Procard Charges		7 ELEVEN 29663		36.05		36.05	R	Inappropriate	Fuel
JUL-05	0921	Projects	PVS Net - Procard Charges		ALADDIN-ZANZIBAR CAFE		29.75		29.75	R	Out-Of-State Expense	Business meals
JUL-05	0921	Projects	PVS Net - Procard Charges		AMZ*SUPERSTORE		54.99		54.99	R	Inappropriate	Small Tools Expense
JUL-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462		60.11		60.11	R	Excessive	Business meals
JUL-05	0921	Projects	PVS Net - Procard Charges		CRACKER BARREL #416		111.39		111.39	R	Excessive	Business meals
JUL-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE		50.00		50.00	R	Excessive	Business meals
JUL-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET		37.00		37.00	R	Out-Of-State Expense	Travel Expense
JUL-05	0921	Projects	PVS Net - Procard Charges		HMSHOST-LAS-AIRPT #033		1.92		1.92	R	Out-Of-State Expense	Travel Expense
JUL-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416		137.76		137.76	R	Inappropriate	2 receitps $100. Employee Appreciation $37.67 Office Su
JUL-05	0921	Projects	PVS Net - Procard Charges		IVARS 25 SEATAC AIRPOR		19.51		19.51	R	Out-Of-State Expense	Travel Expense
JUL-05	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL		51.13		51.13	R	Excessive	Business meals
JUL-05	0921	Payables		Purchase Invoice	LAKE HAVASU CITY	071	50.00		50.00	R	Sponsorship	Permit & License
JUL-05	0921	Projects	PVS Net - Procard Charges		MR. C'S RESTAURANT		193.49		193.49	R	Excessive	Business meals HR related
JUL-05	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE		173.54		173.54	R	Out-Of-State Expense	Business meals in Kingman
JUL-05	0921	Projects	PVS Net - Procard Charges		QUIK MART #33		30.67		30.67	R	Inappropriate	Business meals
JUL-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879		24.46		24.46	R	Inappropriate	Employee meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		56.56		56.56	R	Out-Of-State Expense	Located in Lake Havasu Business meals
JUL-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2		10.50		10.50	R	Inappropriate	Office Supplies
JUL-05	0921	Projects	PVS Net - Procard Charges		XEROX SUPPLY TEXAS		153.87		153.87	R	Questionable Expense	Office Supplies
AUG-05	0921	Projects	PVS Net - Procard Charges		906 FASTRIP FOOD S		47.33		47.33	R	Inappropriate	Business meals
AUG-05	0921	Projects	PVS Net - Procard Charges		AIRTRANAI 33212712643762		228.39		228.39	R	Out-Of-State Expense	Travel Expense
AUG-05	0921	Payables		Purchase Invoice	DANCES WITH OPPORTUNITY LLC	A6:	1,855.62		1,855.62	R	Is This An Annually Recu	This is for 2 years - employee training
AUG-05	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT		114.69		114.69	R	Inappropriate	Employee meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO		60.00		60.00	R	Inappropriate	Employee Flowers
AUG-05	0921	Projects	PVS Net - Procard Charges		GOLD'S GYM		40.00		40.00	R	Inappropriate	agree
AUG-05	0921	Projects	PVS Net - Procard Charges		HILTON SEDONA RESORTIP		437.42		437.42	R	Questionable Expense	Travel Expense
AUG-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416		247.37		247.37	R	Inappropriate	Materials Purchased
AUG-05	0921	Payables		Purchase Invoice	KINGMAN ROTARY CLUB	081	125.00		125.00	R	Sponsorship	Dues
AUG-05	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO		12.00		12.00	R	Out-Of-State Expense	Travel Expense
AUG-05	0921	Payables		Purchase Invoice	NOGALES INTERNATIONAL NEWSPAPER	081	49.00		49.00	R	Inappropriate	Newspaper Subscription
AUG-05	0921	Projects	PVS Net - Procard Charges		P.F. CHANG'S #8000		104.09		104.09	R	Excessive	Business meals standards mtg
AUG-05	0921	Projects	PVS Net - Procard Charges		PLN*NO REFUNDS		452.01		452.01	R	Questionable Expense	Plane Travel Expense
AUG-05	0921	Projects	PVS Net - Procard Charges		PRESCOTT CONVENTION CT		95.96		95.96	R	Questionable Expense	UES Mentoring Program Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		RADISSON HOTELS STES T		115.49		115.49	R	Questionable Expense	Travel Expense
AUG-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879		147.10		147.10	R	Inappropriate	Employee Appreciation BBQ
AUG-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172		52.32		52.32	R	Inappropriate	Employee Appreciation BBQ
AUG-05	0921	Projects	PVS Net - Procard Charges		SEARS DEALER 3089		682.09		682.09	R	Questionable Expense	Office Refrigerator Purchase
AUG-05	0921	Projects	PVS Net - Procard Charges		SHERYL'S HALLMARK #2		7.54		7.54	R	Inappropriate	Sympathy Card

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	e N	DR	CR	Net Amount		RUCO'S COMMENT	UNSE COMMENT
NOV-05	0921	Projects	PVS Net - Procard Charges		RADISSON HOTELS-WOODLA		30.27		30.27	R	Out-Of-State Expense	Travel Expense
NOV-05	0921	Projects	PVS Net - Procard Charges		RAINBOW CRAIG MINI MAR		28.93		28.93	R	Inappropriate	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879		27.24		27.24	R	Inappropriate	Employee meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		SEARS DEALER 3089		498.74		498.74	R	Questionable Expense	Purchase Office Refrigerator
NOV-05	0921	Projects	PVS Net - Procard Charges		STARBUCKS		6.51		6.51	R	Inappropriate	Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		SUNSET STN HOTEL FD		4.95		4.95	R	Out-Of-State Expense	Travel Expense
NOV-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		22.11		22.11	R	Out-Of-State Expense	Located in Lake Havasu Business meals
NOV-05	0921	Projects	PVS Net - Procard Charges		UNITED WAY OF GREATER		100.00		100.00	R	Sponsorship	agree
NOV-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2		97.28		97.28	R	Inappropriate	Office Supplies
NOV-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2		67.87		67.87	R	Inappropriate	Office Supplies
NOV-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2		200.92		200.92	R	Inappropriate	Office Supplies
DEC-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462		100.92		100.92	R	Excessive	Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05290		36.53		36.53	R	Inappropriate	Fuel
DEC-05	0921	Projects	PVS Net - Procard Charges		COFFEE BEAN & TEA LEAF		5.37		5.37	R	Inappropriate	Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		CRACKER BARREL #416		51.73		51.73	R	Excessive	Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT		30.15		30.15	R	Inappropriate	Employee meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET		37.00		37.00	R	Out-Of-State Expense	Travel Expense
DEC-05	0921	Projects	PVS Net - Procard Charges		G & E'S BORDER PRINT S		89.26		89.26	R	Questionable Expense	Office Supplies
DEC-05	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE		222.22		222.22	R	Excessive	Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		KMART 00095281		10.76		10.76	R	Inappropriate	Office Supplies
DEC-05	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO		84.00		84.00	R	Out-Of-State Expense	Travel Expense
DEC-05	0921	Projects	PVS Net - Procard Charges		PALO DURO CREEK GOLF C		7.68		7.68	R	Out-Of-State Expense	Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879		117.99		117.99	R	Inappropriate	Employee meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		SANDY'S		219.95		219.95	R	Questionable Expense	Meeting site rental 30 employee Meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		SHERATON HOTELS & STIP		137.37		137.37	R	Questionable Expense	Travel Expense
DEC-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE		46.41		46.41	R	Out-Of-State Expense	Located in Lake Havasu Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		TONTO APCHE CSNO MZTZL		14.15		14.15	R	Questionable Expense	Business meals
DEC-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2		22.55		22.55	R	Inappropriate	Office Supplies
									25,683.25			

UNS Electric Corporatic
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0923

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	or Invoice Numbe	DR	CR	Net Amount		RUCO'S COMMENT	UNSE COMMET
FEB-06	0923	Projects	PVS Net - Procard Charges		AMZ*SUPERSTORE		54.83		54.83	R	Inappropriate	Oiffice Supplies
JUN-06	0923	Projects	PVS Net - Procard Charges		BELLA DONNA RESTAURANT		62.07		62.07	R	Excessive	Travel and Training
NOV-05	0923	Projects	PVS Net - Procard Charges		CINNABON		8.25		8.25	R	Inappropriate	Travel and training
FEB-06	0923	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LLC	A11906	1,953.13		1,953.13	R	Is This An Annually Recun	This is for 2 years-training
FEB-06	0923	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LLC	A22206	1,990.63		1,990.63	R	Is This An Annually Recun	This is for 2 years- training
JUL-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3064550-50	964.73		964.73	R	Inappropriate	Drinking Water Purchase-Sparklets
AUG-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3378780-50	415.80		415.80	R	Inappropriate	Drinking Water Purchase-Sparklets
OCT-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4053444-50	829.62		829.62	R	Inappropriate	Drinking Water Purchase-Sparklets
OCT-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3701642-50	1,309.22		1,309.22	R	Inappropriate	Drinking Water Purchase-Sparklets
NOV-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4283463-50	608.92		608.92	R	Inappropriate	Drinking Water Purchase-Sparklets
JAN-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4623406-50	337.87		337.87	R	Inappropriate	Drinking Water Purchase-Sparklets
MAR-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4742326-50	27.04		27.04	R	Inappropriate	Drinking Water Purchase-Sparklets
APR-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4749208-50	1,106.46		1,106.46	R	Inappropriate	Drinking Water Purchase-Sparklets
MAY-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4756016-50	574.94		574.94	R	Inappropriate	Drinking Water Purchase-Sparklets
JUN-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	106877	789.57		789.57	R	Inappropriate	Drinking Water Purchase-Sparklets
NOV-05	0923	Projects	PVS Net - Procard Charges		EDGEWATER HOTEL F/B		58.82		58.82	R	Out-Of-State Expense	Business travel
SEP-05	0923	Projects	PVS Net - Procard Charges		EMBASSY SUITES FLAGTIP		218.02		218.02	R	Questionable Expense	Training
MAR-06	0923	Projects	PVS Net - Procard Charges		EMBASSY SUITES FLAGTIP		98.00		98.00	R	Questionable Expense	Training
APR-06	0923	Projects	PVS Net - Procard Charges		FTD*SUTCLIFFE FLORAL		21.62		21.62	R	Inappropriate	Office Supplies
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO ADV DEP		126.44		126.44	R	Out-Of-State Expense	Travel and Training
JUL-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO FOOD &		19.34		19.34	R	Out-Of-State Expense	Travel and Training
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO FOOD &		22.28		22.28	R	Out-Of-State Expense	Travel and Training
JUL-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO LAUGHLI		83.93		83.93	R	Out-Of-State Expense	Travel and Training
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO LAUGHLI		245.57		245.57	R	Out-Of-State Expense	Travel and Training
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO RETAIL		2.00		2.00	R	Out-Of-State Expense	Travel and Training
NOV-05	0923	Projects	PVS Net - Procard Charges		HOLIDAY INN EXPRESSTIP		39.50		39.50	R	Questionable Expense	Travel and Training
NOV-05	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		20.65		20.65	R	Inappropriate	Employee meal expense
DEC-05	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		22.03		22.03	R	Inappropriate	Employee meal expense
FEB-06	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		18.70		18.70	R	Inappropriate	Employee meal expense
MAY-06	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		17.77		17.77	R	Inappropriate	Employee meal expense
AUG-05	0923	Payables		Purchase Invoices USD	INFINITY POOL & SPA	447696	57.50		57.50	R	Inappropriate	Damage to Customer Property Expense
NOV-05	0923	Projects	PVS Net - Procard Charges		JACKSONS GRILL		124.19		124.19	R	Excessive	Several employees, business meals
JUN-06	0923	Projects	PVS Net - Procard Charges		LOWNS COSTUMES AND NOV		37.50		37.50	R	Inappropriate	agree
JUL-05	0923	Projects	PVS Net - Procard Charges		LUXOR PYRAMID CAFE		22.00		22.00	R	Out-Of-State Expense	Travel and Training
SEP-05	0923	Projects	PVS Net - Procard Charges		MAIN STREET CATERING		178.98		178.98	R	Excessive	Employee Meeting
FEB-06	0923	Projects	PVS Net - Procard Charges		MARIPOSA COMMUNITY HLT		145.15		145.15	R	Sponsorship	CDL License Physical Examination
APR-06	0923	Projects	PVS Net - Procard Charges		MARRIOTT HOTELS WEST L		151.52		151.52	R	Out-Of-State Expense	Travel and Training
MAR-06	0923	Projects	PVS Net - Procard Charges		MERRIBELL CORPORATION		62.08		62.08	R	Inappropriate	Safety of the year Plaque
APR-06	0923	Projects	PVS Net - Procard Charges		MERRIBELL CORPORATION		28.93		28.93	R	Inappropriate	Safety of the year Plaque
DEC-05	0923	Projects	PVS Net - Procard Charges		MOHAVE COMMUNITY C		70.00		70.00	R	Sponsorship	agree
JUL-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	0021660-IN	5,004.89		5,004.89	R	Lobbying	Monthly Safety and Training Program
JUL-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	0021788-IN	5,004.89		5,004.89	R	Lobbying	Monthly Safety and Training Program
SEP-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	0022010-IN	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
SEP-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	0022150-IN	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
OCT-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	00044934	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
NOV-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	00045422	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
DEC-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	00046547	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
DEC-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	00046571	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
JAN-06	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	00046839	3,824.30		3,824.30	R	Lobbying	Monthly Safety and Training Program
MAR-06	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASSO(	0047740	7,648.60		7,648.60	R	Lobbying	Monthly Safety and Training Program
SEP-05	0923	Projects	PVS Net - Procard Charges		OPEN ROAD TOURES INC		125.00		125.00	R	Inappropriate	Travel and Training
SEP-05	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		26.63		26.63	R	Inappropriate	Business meals
MAR-06	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		15.31		15.31	R	Inappropriate	Business meals
APR-06	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		106.11		106.11	R	Inappropriate	Business meals
JUL-05	0923	Projects	PVS Net - Procard Charges		PASTO		103.52		103.52	R	Excessive	Business meals
AUG-05	0923	Projects	PVS Net - Procard Charges		PRESCOTT CONVENTION CT		388.93		388.93	R	Sponsorship	Training expense
DEC-05	0923	Projects	PVS Net - Procard Charges		PRESCOTT CONVENTION CT		42.59		42.59	R	Sponsorship	Training expense
NOV-05	0923	Projects	PVS Net - Procard Charges		RADISSON HOTELS-WOODLA		12.96		12.96	R	Out-Of-State Expense	Located in Flagstaff-employee meal
MAR-06	0923	Projects	PVS Net - Procard Charges		RENE@TLAQUEPAQUE		24.18		24.18	R	Questionable Expense	Employee meal expense
OCT-05	0923	Projects	PVS Net - Procard Charges		RODS STEAK HOUSE		58.57		58.57	R	Excessive	2 Employee meal expense
SEP-05	0923	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020289		11.54		11.54	R	Inappropriate	kitchen supplies
NOV-05	0923	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6		62.16		62.16	R	Inappropriate	Employee Meeting
FEB-06	0923	Projects	PVS Net - Procard Charges		THE HOME DEPOT #8488		290.00		290.00	R	Inappropriate	Repl mini blinds in the Lobby Santa Cruz
OCT-05	0923	Projects	PVS Net - Procard Charges		WESTIN KIERLAND RESTIP		136.18		136.18	R	Questionable Expense	Travel and Training

GL Period	FERC	y Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	ɔice Numbei	DR	CR	Net Amount		RUCO'S COMMENT	UNS	ΛMET
JUL-05	0923	Projects	PVS Net - Procard Charges		WINDROCK AVIATION		332.00		332.00	R	Questionable Expense	Travel and Training	
MAR-06	0923	Projects	PVS Net - Procard Charges		WOODLANDS PLAZA HOTEL		75.98		75.98	R	Out-Of-State Expense	Travel and training in Flagstaff	
FEB-06	0923	Projects	PVS Net - Procard Charges		WOODLANDS WASH		8.00		8.00	R	Out-Of-State Expense	Travel and training in Flagstaff	
SEP-05	0923	Projects	PVS Net - Procard Charges		YAVAPAI BUS TOURS		235.00		235.00	R	Inappropriate	Travel and Training	
									59,408.74				

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0930

GL Period	FERC	uery Sour	PA Transaction Source	Gl JE Name	lu	Vendor Name	Invoice Number	DR	CR	Net Amount		RUCO'S COMMENT	UNSE COMMET
NOV-05	0930	Projects	PVS Net - Procard Charges			3 MARGARITAS CASA BONI		62.60		62.60	R	Inappropriate	Business Meals 2 employees
APR-06	0930	Projects	PVS Net - Procard Charges			ALBERTSONS #1027 S9H		12.27		12.27	R	Inappropriate	refreshments for meeting
DEC-05	0930	Payables		Purchase Invoices USD		ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR	2006-25	250.00		250.00	R	Does Not Benefit Ratepayers	dues
JUL-05	0930	Payables		Purchase Invoices USD		ARIZONA UTILITY INVESTORS ASSOC	072705 500000	2,500.00		2,500.00	R	Does Not Benefit Ratepayers	agree
OCT-05	0930	Payables		Purchase Invoices USD		AUSA	100705 15000	150.00		150.00	R	Does Not Benefit Ratepayers	Travel and training
JAN-06	0930	Payables		Purchase Invoices USD		AUSA	011706 10000	100.00		100.00	R	Does Not Benefit Ratepayers	Travel and training
MAR-06	0930	Payables		Purchase Invoices USD		AUSA	032906 35000	350.00		350.00	R	Does Not Benefit Ratepayers	Travel and training
JUL-05	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		94.78		94.78	R	Inappropriate	business meal 5 employees
OCT-05	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		50.00		50.00	R	Inappropriate	Empl recognition gift certificate
JAN-06	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		98.11		98.11	R	Inappropriate	Line Crew Recognition 5 employees
AUG-05	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		10.17		10.17	R	Inappropriate	Safety Committee Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		7.20		7.20	R	Inappropriate	Safety Committee Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		13.76		13.76	R	Inappropriate	Safety Committee Meeting
OCT-05	0930	Projects	PVS Net - Procard Charges			BASHAS 60 SYW		4.54		4.54	R	Inappropriate	Safety Committee Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			BLACK BEAR DINER N		287.78		287.78	R	Excessive	Line crew employee recognition 20 employees
NOV-05	0930	Payables		Purchase Invoices USD		BOYS & GIRLS CLUB OF NOGALES	110805 3500	35.00		35.00	R	Sponsorship	agree
JUL-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	15944	3,712.50		3,712.50	R	Is This An Annually Recurring Expense	This is for 2 years - employee training
SEP-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	16252	974.00		974.00	R	Is This An Annually Recurring Expense	This is for 2 years - employee training
SEP-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	16347	4,677.75		4,677.75	R	Is This An Annually Recurring Expense	This is for 2 years - employee training
MAY-06	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	17808	3,712.50		3,712.50	R	Is This An Annually Recurring Expense	This is for 2 years - employee training
JUN-06	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	18010	711.00		711.00	R	Is This An Annually Recurring Expense	This is for 2 years - employee training
NOV-05	0930	Projects	PVS Net - Procard Charges			BUSTER S RESTAURANT		75.81		75.81	R	Excessive	Employee Training Meal 3 empl
FEB-06	0930	Projects	PVS Net - Procard Charges			BUSTERS		88.63		88.63	R	Excessive	business dinner expenses 3 employees
JAN-06	0930	Projects	PVS Net - Procard Charges			CHA-BONES		191.25		191.25	R	Excessive	3 receipts 15 employees Lunch
NOV-05	0930	Projects	PVS Net - Procard Charges			CHILI'S GRI04900010496		52.04		52.04	R	Excessive	Outage response 4 empl
FEB-06	0930	Projects	PVS Net - Procard Charges			CHILI'S GRI04900010496		79.53		79.53	R	Excessive	Business meals
JUN-06	0930	Payables		Purchase Invoices USD		CITY OF BULLHEAD CITY	062506 5417	54.17		54.17	R	Sponsorship	dues
AUG-05	0930	Payables		Purchase Invoices USD		DANCES WITH OPPORTUNITY LLC	A82305	1,855.63		1,855.63	R	Is This An Annually Recurring Expense	Employee training annual
OCT-05	0930	Payables		Purchase Invoices USD		DANCES WITH OPPORTUNITY LLC	A91405	3,711.25		3,711.25	R	Is This An Annually Recurring Expense	Employee training annual
NOV-05	0930	Payables		Purchase Invoices USD		DANCES WITH OPPORTUNITY LLC	A101905	3,711.25		3,711.25	R	Is This An Annually Recurring Expense	Employee training annual
JUN-06	0930	Projects	PVS Net - Procard Charges			DIAMOND BACKS MERCHNDI		47.57		47.57	R	Inappropriate	Agree, Donation to Boy's and Girl's Club
JUL-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		107.68		107.68	R	Inappropriate	Several receipts combined:Weekly Safety Meeting
NOV-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		116.89		116.89	R	Inappropriate	Several receipts combined:Weekly Safety Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		48.39		48.39	R	Inappropriate	Several receipts combined:Weekly Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		103.36		103.36	R	Inappropriate	Several receipts combined:Weekly Safety Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		101.74		101.74	R	Inappropriate	Several receipts combined:Weekly Safety Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		77.52		77.52	R	Inappropriate	Several receipts combined:Weekly Safety Meeting
JUL-05	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000025467C	24,071.00		24,071.00	R	Lobbying	See repsone STF 11.11 Membership dues
JAN-06	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000038367	2,801.90		2,801.90	R	Lobbying	See repsone STF 11.11 Membership dues
JAN-06	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000038292	10,000.00		10,000.00	R	Lobbying	See repsone STF 11.11 Membership dues
NOV-05	0930	Projects	PVS Net - Procard Charges			ELEPHANT BAR # 219		173.56		173.56	R	Excessive	ASAU Conf, Chandler AZ 2 receipts $37.35
JUL-05	0930	Projects	PVS Net - Procard Charges			EXPRESS STOP		11.65		11.65	R	Inappropriate	business related
NOV-05	0930	Projects	PVS Net - Procard Charges			FIREBIRDS OF CHANDLER		168.20		168.20	R	Sponsorship	ASAU Conference Meals
APR-06	0930	Projects	PVS Net - Procard Charges			FLAMINGO ALTA VILLA		59.64		59.64	R	Out-Of-State Expense	Business meals
FEB-06	0930	Projects	PVS Net - Procard Charges			FRESH PRODUCE ASSOC		250.00		250.00	R	Sponsorship	Dues
SEP-05	0930	Payables		Purchase Invoices USD		GOLDEN VALLEY CHAMBER OF COMMERCE	JULY 2005	35.00		35.00	R	Sponsorship	Dues
OCT-05	0930	Payables		Purchase Invoices USD		GOLDEN VALLEY CHAMBER OF COMMERCE	07/2005	35.00		35.00	R	Sponsorship	Dues
OCT-05	0930	Projects	PVS Net - Procard Charges			H.L.A FRONT DESK #1		229.61		229.61	R	Questionable Expense	Travel expenses
AUG-05	0930	Projects	PVS Net - Procard Charges			HAMPTON INN TIP		494.25		494.25	R	Questionable Expense	Meterman Training
APR-06	0930	Projects	PVS Net - Procard Charges			HMS HOST-LAS-AIRPT#241		7.29		7.29	R	Out-Of-State Expense	Travel and Training
OCT-05	0930	Projects	PVS Net - Procard Charges			HOOTERS OF OVERLAND PA		58.87		58.87	R	Out-Of-State Expense	SWESE Safety Conference
APR-06	0930	Projects	PVS Net - Procard Charges			HOTEL CONTESSA-HOTEL		1,330.98		1,330.98	R	Out-Of-State Expense	Training expenses
JAN-06	0930	Projects	PVS Net - Procard Charges			IHOP #3033		80.59		80.59	R	Excessive	Engineering Dept Lunch 7 empployees
MAR-06	0930	Projects	PVS Net - Procard Charges			JAVELINA CANTINA		56.96		56.96	R	Excessive	Safety Committee Meeting Lunch 4 employees
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN CHAMBER OF COMMERCE	207916A	325.00		325.00	R	Sponsorship	dues
MAY-06	0930	Projects	PVS Net - Procard Charges			KINGMAN DELI, THE		81.42		81.42	R	Excessive	Grants that Make a Difference Workshop 3 people Non Profit Agencies
OCT-05	0930	Payables		Purchase Invoices USD		KINGMAN MOHAVE LIONS CLUB	1376	60.00		60.00	R	Sponsorship	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN ROTARY CLUB	102605 12500	125.00		125.00	R	Sponsorship	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN ROUTE 66 ROTARY CLUB	100105 13250	132.50		132.50	R	Sponsorship	Dues
JUN-06	0930	Payables		Purchase Invoices USD		KINGMAN ROUTE 66 ROTARY CLUB	060506 12500	125.00		125.00	R	Sponsorship	Dues
AUG-05	0930	Payables		Purchase Invoices USD		KINGSMEN	081505 12500	125.00		125.00	R	Sponsorship	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KIWANIS CLUB OF LAKE HAVASU	110305 66600	666.00		666.00	R	Sponsorship	Corporate Dues
DEC-05	0930	Projects	PVS Net - Procard Charges			KMART 00037077		30.44		30.44	R	Inappropriate	supplies
MAY-06	0930	Projects	PVS Net - Procard Charges			LAKE HAVASU CHAMBER OF		505.00		505.00	R	Sponsorship	Dues
APR-06	0930	Projects	PVS Net - Procard Charges			LOS PRIMOS BAR & GRILL		96.21		96.21	R	Excessive	Bargaining Unit OT meal 7 employees
DEC-05	0930	Projects	PVS Net - Procard Charges			MARIE CALLENDER'S #245		567.80		567.80	R	Excessive	March of Dimes---Reimbursed upon sale
AUG-05	0930	Projects	PVS Net - Procard Charges			MCCARRAN INT L AVIATIO		62.00		62.00	R	Out-Of-State Expense	Long Term Parking--training
OCT-05	0930	Projects	PVS Net - Procard Charges			MCCARRAN INT L AVIATIO		41.00		41.00	R	Out-Of-State Expense	Long Term Parking--training
AUG-05	0930	Payables		Purchase Invoices USD		MINKUS ADVERTISING SPECIALTIES	052917	536.50		536.50	R	Inappropriate	agree
AUG-05	0930	Payables		Purchase Invoices USD		MINKUS ADVERTISING SPECIALTIES	052918	1,118.00		1,118.00	R	Inappropriate	agree
AUG-05	0930	Payables		Purchase Invoices USD		MOHAVE MUSEUM OF HISTORY & ARTS	080305 20000	200.00		200.00	R	Sponsorship	agree
NOV-05	0930	Projects	PVS Net - Procard Charges			N AWLINS ON MONTEZUMA		340.71		340.71	R	Questionable Expense	agree
JUN-06	0930	Projects	PVS Net - Procard Charges			NATURAL TEASE SPORTWEA		99.87		99.87	R	Inappropriate	agree
JUN-06	0930	Payables		Purchase Invoices USD		NOGALES-SANTA CRUZ CHAMBER OF COMMERCE	060906 6000	60.00		60.00	R	Sponsorship	Dues
JUL-05	0930	Projects	PVS Net - Procard Charges			NORTHWEST PUBLIC POW		210.00		210.00	R	Lobbying	Dues
MAY-06	0930	Projects	PVS Net - Procard Charges			ORB*W3BQL5		209.35		209.35	R	Questionable Expense	Lodging in Tucson for Business meetings
OCT-05	0930	Projects	PVS Net - Procard Charges			OUTBACK #0317		55.52		55.52	R	Excessive	Business Meals 2 employees
NOV-05	0930	Projects	PVS Net - Procard Charges			OUTBACK #0317		142.86		142.86	R	Excessive	.Business meal 2 employees
OCT-05	0930	Projects	PVS Net - Procard Charges			PIZZA HUT 21200Q34		168.89		168.89	R	Excessive	Business meal 8 employees
FEB-06	0930	Projects	PVS Net - Procard Charges			PIZZA HUT #00942700Q34		119.66		119.66	R	Excessive	Business Meeting refreshements
FEB-06	0930	Projects	PVS Net - Procard Charges			PLUSHLAND INC		174.00		174.00	R	Inappropriate	agree
MAY-06	0930	Projects	PVS Net - Procard Charges			PRESCOTT COLLEGE		253.00		253.00	R	Questionable Expense	Meeting
AUG-05	0930	Projects	PVS Net - Procard Charges			PRESCOTT CONVENTION CT		171.74		171.74	R	Questionable Expense	UES Mentoring Program Meeting
JUN-06	0930	Projects	PVS Net - Procard Charges			PRONTO MARKET		27.01		27.01	R	Inappropriate	refreshments for meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			R A W SPORTS		50.00		50.00	R	Inappropriate	Employee appreciation Award
JUN-06	0930	Projects	PVS Net - Procard Charges			R A W SPORTS		200.53		200.53	R	Inappropriate	Agree - March of Dimes Charity Org gift cards

GL Period	FERC	uery Sourc	insaction Source	Gl JE Name	tu	Vendor Name	Invoic	ar	DR	CR	Net Amount		RUCO'S COMMENT	UNSE
MAY-06	0930	Projects	P. ..l - Procard Charges			RADISSON HOTELS-WOODLA			14.51		14.51	R	Out-Of-State Expense	meal-training
APR-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00002162			32.21		32.21	R	Inappropriate	3 receipts Safley Weekly meetings refreshments
DEC-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00012294			250.42		250.42	R	Inappropriate	15 frozen Turkies for CATS Project
NOV-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879			23.78		23.76	R	Inappropriate	Weekly Safety Meeting refreshments
DEC-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879			31.01		31.01	R	Inappropriate	Weekly Safety Meeting refreshments
JAN-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879			30.79		30.79	R	Inappropriate	Weekly Safety Meeting refreshments
FEB-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879			85.76		85.76	R	Inappropriate	Weekly Safety Meeting refreshments
MAR-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879			28.76		28.76	R	Inappropriate	Weekly Safety Meeting refreshments
DEC-05	0930	Projects	PVS Net - Procard Charges			SANDY'S			513.24		513.24	R	Questionable Expense	Meeting site rental 30 employee lunches Safety Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			SANDY'S			65.35		65.35	R	Questionable Expense	Meeting site rental 30 employee refreshments Safety Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			SANDY'S			133.73		133.73	R	Questionable Expense	Meeting site rental 30 employee refreshments Safety Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SEARS DEALER 3537			70.09		70.09	R	Questionable Expense	Torque Tool Wrench Purchase
JUL-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			52.88		52.88	R	Inappropriate	5 receipts weekly Safety Meetings refreshments
AUG-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			60.73		60.73	R	Inappropriate	Weekly Safety Meeting refreshments
SEP-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			45.88		45.88	R	Inappropriate	4 receipts weekly Safety meetings refreshements
OCT-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			45.89		45.89	R	Inappropriate	Weekly Safety Meeting refreshments
NOV-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			64.44		64.44	R	Inappropriate	Weekly Safety Meeting refreshments
DEC-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			41.41		41.41	R	Inappropriate	3 receipts weekly Safety meeting refreshments
JAN-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			29.44		29.44	R	Inappropriate	Weekly Safety Meeting refreshments
FEB-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			38.23		38.23	R	Inappropriate	3 receipts weekly Safety meeting refreshments
MAR-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6			43.90		43.90	R	Inappropriate	4 receipts weekly Safety meeting refreshments
MAY-06	0930	Projects	PVS Net - Procard Charges			SOTO'S P/K OUTPOST			91.23		91.23	R	Questionable Expense	Employee Meals
APR-06	0930	Projects	PVS Net - Procard Charges			STEERS AND BEERS			62.56		62.56	R	Excessive	Employee business meal 2 employees
FEB-06	0930	Projects	PVS Net - Procard Charges			TERRIBLES #148			14.98		14.98	R	Out-Of-State Expense	Located in Lake Havasu, Refreshments for Safety Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			TERRIBLES #148			23.67		23.67	R	Out-Of-State Expense	Located in Lake Havasu, Refreshments for Safety Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			TEXAS LAND & CATTLE#71			71.79		71.79	R	Out-Of-State Expense	2 employees dinners
JUN-06	0930	Projects	PVS Net - Procard Charges			THE HOME DEPOT #0416			323.26		323.26	R	Questionable Expense	agree
DEC-05	0930	Projects	PVS Net - Procard Charges			THE HOME DEPOT 403			30.73		30.73	R	Questionable Expense	agree
NOV-05	0930	Projects	PVS Net - Procard Charges			TOMATO CAFE			35.30		35.30	R	Out-Of-State Expense	Training Lunch 3 employees Located in Lake Havasu
FEB-06	0930	Projects	PVS Net - Procard Charges			VILLA S FOOD MARKET			40.67		40.67	R	Inappropriate	Pot Luch for employee retirement
MAY-06	0930	Projects	PVS Net - Procard Charges			VILLA S FOOD MARKET			9.37		9.37	R	Inappropriate	Plates-Utensils for above Pot Luck
JUL-05	0930	Projects	PVS Net - Procard Charges			WAL MART			45.50		45.50	R	Inappropriate	2 receipts Galorade for Crews
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL MART			36.66		36.66	R	Inappropriate	Galorade for Crews
SEP-05	0930	Projects	PVS Net - Procard Charges			WALGREEN 00052Q39			7.73		7.73	R	Inappropriate	film development for disposible camera for crews
FEB-06	0930	Projects	PVS Net - Procard Charges			WALGREEN 00052Q39			41.30		41.30	R	Inappropriate	film development for disposible camera for crews
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1324 SE2			47.55		47.55	R	Inappropriate	Office Supplies
JUN-06	0930	Projects	PVS Net - Procard Charges			WAL-MART #1324 SE2			100.79		100.79	R	Inappropriate	Fans for Lobby
JUL-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364			24.90		24.90	R	Inappropriate	Galorade for Crews
AUG-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364			23.70		23.70	R	Inappropriate	Galorade for Crews
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364			41.11		41.11	R	Inappropriate	Galorade for Crews
JUN-06	0930	Projects	PVS Net - Procard Charges			WAL-MART #2051 SE2			262.83		262.83	R	Inappropriate	March of Dimes
SEP-05	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2			1.78		1.78	R	Inappropriate	Office Supplies
FEB-06	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2			25.43		25.43	R	Inappropriate	Air Fresheners due to Refriderator malfunction
JUN-06	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2			24.95		24.95	R	Inappropriate	Cleaninig supplies
NOV-05	0930	Projects	PVS Net - Procard Charges			WOODLANDS PLAZA HOTEL			1,167.51		1,167.51	R	Out-Of-State Expense	Located in Flagstaff training
JAN-06	0930	Projects	PVS Net - Procard Charges			WOODLANDS PLAZA HOTEL			1,087.58		1,087.58	R	Out-Of-State Expense	Located in Flagstaff training
FEB-06	0930	Projects	PVS Net - Procard Charges			WOODLANDS PLAZA HOTEL			355.48		355.48	R	Out-Of-State Expense	Located in Flagstaff training
JUN-06	0930	Projects	PVS Net - Procard Charges			WOODLANDS PLAZA HOTEL			470.81		470.81	R	Out-Of-State Expense	Located in Flagstaff training
											81,352.78			

EXHIBIT
RUCO-5
Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 28, 2007

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding UNS Electric Corporation's ("Company" or "UNS") application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for electric service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended June 30, 2006.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the Company's overall revenue requirement and rate design. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of five sets of data requests, the review and analysis of Company responses to Arizona Corporation Commission ("Commission" or "ACC") Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to UNS.

In Decision No. 66028, dated July 03, 2003, the Commission approved a Settlement Agreement, which authorized UNS to acquire the gas and electric assets of Citizens Communications Company ("Citizens"). The Settlement Agreement required present rates and charges for utility service to remain unchanged. The test year used in determining the present rates was the 12-month period ending March 31, 1995.

Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income, revenue requirements and rate design. RUCO's witness Mr. William Rigsby will provide an analysis of the cost of capital.

RUCO's witness Ms. Marylee Diaz Cortez will also address additional issues related to rate base, operating income, rate design and revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-18.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and rate design issues addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

Fair Value Rate Base – This adjustment states the fair value rate base by giving equal weighting (50/50 split) to RUCO's adjusted original cost rate base and RUCO's calculation of the reconstruction cost new depreciated rate base.

Accumulated Depreciation – This adjustment reflects RUCO's computation of the test-year level of accumulated depreciation.

Acquisition Adjustment – No Adjustment.

Plant Held For Future Use – No Adjustment.

Construction Work In Progress – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Accumulated Deferred Income Taxes - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Allowance For Working Capital - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Operating Income

Customer Annualization - No adjustment.

Weather Normalization - No adjustment.

Service Fees and Late Fees - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Purchased Power Derivatives - No adjustment.

Demand Side Management and Renewables - No adjustment.

Customer Assistance Residential Energy Support – No adjustment.

Payroll - No adjustment.

Payroll Tax - No adjustment.

Pensions and Benefits – This adjustment to benefit expenses removes inappropriate expenditures not necessary in the provisioning of electric service.

Post-Retirement Medical - No adjustment.

Worker's Compensation – This adjustment converts the amount reflected in the test-year operating expense from a cash basis to an accrual.

Incentive Compensation – This adjustment removes all incentive compensation expenses, because the awards were paid despite non-performance of goals and did not provide additional benefits to ratepayers.

Rate Case Expense – This adjustment is based on RUCO's determination of the fair and reasonable cost to UNS ratepayers for this application process.

Bad Debt Expense – RUCO witness Ms. Diaz Cortez addresses this adjustment.

Interest On Customer Deposits – No adjustment.

Operating Lease Expense - No adjustment.

Fleet Fuel Expense - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Postage Expense – This adjustment reflects the RUCO's annualization of the customer base and a known and measurable postal increase.

Out Of Period Expense - No adjustment.

Year End Accurals - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Franchise Fee Expense - No adjustment.

Membership Dues - No adjustment.

Capitalized Administration and General Expenses - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Depreciation and Property Tax For Construction Work In Progress - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Common Systems Allocations - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Operating Systems Allocations - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Corporate Cost Allocations - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Annualized Depreciation and Amortization Expenses– This adjustment reflects the level of test-year depreciation expense based on RUCO's adjusted gross plant in service and the Company–proposed depreciation rates.

Valencia Turbine Fuel - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Property Tax – This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Supplemental Executive Retirement Plan – This adjustment reflects RUCO's disallowance of the supplemental executive retirement plan.

RUCO Adjustments To Test-Year Operating Expenses – This adjustment to operating expenses removes inappropriate expenditures not necessary in the provisioning of electric service.

RUCO Adjustment To Overhead Line Maintenance Expense – This adjustment normalizes the test-year level of overhead line maintenance expense.

Customer Service Cost Allocations – This adjustment reflects the appropriate level of customer service costs given the quality of the service.

Non-Recurring/Atypical Expenses – This adjustment removes costs not expected to recur and considered atypical for inclusion in test year expenses.

Outside Services – DSM - RUCO witness Ms. Diaz Cortez addresses this adjustment.

Income Tax – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, RUCO is recommending that the increase in the Company's revenue requirement not exceed:

UNS	RUCO	DIFFERENCE
$8,507,097	$1,253,233	($7,253,864)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

UNS	RUCO	DIFFERENCE
5.37 %	0.79 %	-4.58 %

RUCO's recommended decrease in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base

("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

UNS	RUCO	DIFFERENCE
$177,802,340	$161,618,144	($16,184,196)

The detail supporting RUCO's recommended rate base is presented on Schedules RLM-3, RLM-4, RLM-5 and RLM-6.

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

UNS	RUCO	DIFFERENCE
$13,946,320	$11,169,957	($2,776,363)

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

RATE BASE

Determination Of Fair Value Rate Base

Q. Please explain the basis for your determination of the FVRB as shown on Schedule RLM-1.

A. RUCO's determination of the FVRB consists of three elements. First, the value of the OCRB was restated to reflect RUCO's adjustments to the various rate base determinants. Second, the value of the RCND was computed. As shown on supporting Schedule RLM-2, RUCO computed RCND by multiplying RUCO's OCRB by the ratio of the Company's OCRB to its RCND as filed. Third, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Ms. Diaz Cortez. As shown on Schedule RLM-3, I was responsible for Adjustment No. 2. These adjustments established the initial level and subsequently calculated the present test-year level of gross plant in service and accumulated depreciation. Ms. Diaz Cortez analyzed the remaining rate base adjustments.

<u>RUCO Rate Base Adjustment No. 2 – Adjust Understated Accumulated Depreciation</u>

Q. Please provide the background to RUCO's adjustment.

A. By analyzing the Company's responses to several RUCO data requests (i.e. 1.08, 2.09, 2.10, 4.04 and 5.03), I was able to substantiate the Company's recorded level of gross plant in service as $380,192,497 as of June 30, 2006.

However, UNS states in the instant filing the value of accumulated depreciation of $159,524,693 as of end of the test year. RUCO calculated the appropriate level of accumulated depreciation as $161,819,805, a difference of $2,295,112. RUCO's computation is based on the adjustments in annual gross plant levels and the authorized depreciation rates as provided by the Company.

Therefore, as shown on Schedule RLM-4, column (C), this adjustment decreases the rate base by $2,295,112.

OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. The Company proposed thirty-one adjustments to its historical test-year operating income. RUCO analyzed the Company's adjustments and made several additional adjustments to the operating income as filed by the Company. The testimony of RUCO witness Ms. Diaz Cortez discusses twenty of the adjustments, while I was responsible for reviewing eleven of the adjustments the Company proposes to its test-year operating income. Finally, as a result of its discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

Operating Income Adjustment No. 2 – Pension and Benefits

Q. Please explain your adjustment to reduce the pension and benefits expenses.

A. My adjustment reflects the information provided by the Company in its response to Staff data request 3.81. UNS quantifies the test-year expenses identified as gifts, awards, employee dinners, picnics and social events. RUCO considers these benefits as an inappropriate financial burden on ratepayers and therefore, removed them from operating expenses.

As shown on Schedule RLM-8, column (C), I reversed the Company's benefit expenses as listed on UNS response to Staff data request 3.81 and decreased test-year operating expenses by $11,612.

Operating Income Adjustment No. 3 – Worker's Compensation

Q. Please discuss the Company's proposed worker's compensation expense adjustment.

A. The Company has converted the amount reflected in the test-year operating expenses from an accrual to a cash basis.

Q. Please explain RUCO's treatment of the Company's proposed worker's compensation expense adjustment.

A. Absent a Commission ruling, RUCO does not consider it appropriate to arbitrarily change from an accrual to a cash basis. The UNS argument that since worker's compensation is a benefit provided to former or inactive employees it should receive the same treatment as post employment benefits is hollow. The Company failed to provide documentation segregating any worker's compensation benefits that are included in post employment benefit obligations.

Furthermore, workers' compensation certainly is provided to active employees for which post-retirement accounting would not be applicable.

The Company accepted the same adjustment as recommended by RUCO in the recently filed UNS Gas rate case.

Therefore, as shown on Schedule RLM-8, column (D), I reversed the Company's cash treatment of worker's compensation expense to an accrual basis and decreased test-year operating expenses by $63,252.

Operating Income Adjustment No. 4 – Incentive Compensation

Q. Please provide the background for this adjustment.

A. In 2004, the Unisource Energy Corporation awarded incentive payments under the Performance Enhancement Plan ("PEP").

The PEP is only eligible for a select group of non-union employees and is paid after meeting certain performance goals, including certain financial goals.

In 2005, Unisource Energy Corporation did not meet the PEP financial goals; and therefore, no payments under the PEP program were awarded. Nevertheless, the Board of Directors authorized a Special Recognition Award to these non-union employees in recognition of their accomplishments; however, this special award was less than the payment awarded in 2004.

The Company's adjusted test-year expense incorporates the average of the 2004 PEP bonus and the 2005 Special Recognition Award.

Q. Please continue and provide an explanation for RUCO's adjustment to the incentive compensation expenses.

A. After reviewing the Company's response to RUCO's data requests 2.13 and Staff data requests 3.83 and 3.113, it became apparent the ratepayers should not be burdened with the Board of Directors' arbitrary decision to authorize a Special Recognition Award to select UNS employees when they did not meet Unisource Energy's 2005 financial performance goal. This "Special" award is unique and does not meet the criteria of a typical and recurring test-year expense; moreover, it rewards employees for non-performance.

RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. Therefore, RUCO dismisses the Company's proposal to average the 2005 Special Recognition Award with the 2004 PEP program.

Further to RUCO's objection to averaging the incentive compensation expenses over two years, the Company states that 60 percent of the PEP bonus is directly related to financial performance and operational cost containment. Stockholders are the beneficiaries of the achievement of these financial components. This is particularly true between rate cases. Any additional profit the Company is able to achieve between rate cases accrues solely to the Company's stockholders. Accordingly, since stockholders stand to gain from the achievement of the financial component, stockholders should bear all of the cost of this portion of the incentive compensation. These costs should not be considered for inclusion in rates.

Moreover, RUCO consistently scrutinizes any incentive compensation thoroughly to ensure ratepayers receive adequate benefit from the expense incurred. While the majority of a customer's interfacing with the Company is done through the rank and file unionized employees who are not eligible for any PEP compensation, the perceived incremental increase in customer service generated by this incentive package would not be cost beneficial to ratepayers.

Therefore, RUCO disallows the Company's special test-year compensation bonus and would consider the PEP program (had it been implemented in the test year) discriminatory because the benefit is provided only to a subset of employees. The bonus is also of limited incremental benefit to the ratepayers because the benefit is offered to a class of employees that does not directly affect the service quality of customers.

As shown on Schedule RLM-8, column (E), my adjustment decreases adjusted test-year expenses by $106,567.

Operating Income Adjustment No. 5 – Rate Case Expense

Q. Please discuss your review of the Company's proposed rate case expenses.

A. The Company has budgeted $600,000 for rate case expenses. RUCO has a concern over the reasonableness of such a large financial burden to the ratepayers from this requested adjustment. In comparison, RUCO recommended $251,000 as the appropriate level of rate case expense in UNS's recently filed Gas Division rate case; Docket No. G-04204A-06-0463.

Pending the Commission's approval or rejection of RUCO's recommended rate case expense for the UNS Gas Division, RUCO believes the instant case warrants the equivalent level of rate case expense because of the similarities in Company witnesses, testimonies and schedules.

Therefore, this adjustment reduces annual rate case expense from the Company's proposed level of $200,000 ($600,000 / 3 years) to RUCO's recommended level of $83,667 ($251,000 / 3 years).

As shown on Schedule RLM-8, Column (F), this adjustment decreased test-year expenses by $116,333.

Operating Income Adjustment No. 8 – Postage Expense

Q. Please explain your adjustment to reduce the postage expenses.

A. My adjustment consists of two elements. First, I increased the expense to recognize two changes in postal rates, effective January 8, 2006 and May 14, 2007.

Second, I annualized the test-year postage expense to match RUCO's annualized customer count.

As shown on Schedule RLM-8, column (I) and supporting Schedule RLM-9, my adjustment decreases adjusted test-year expenses by $37,956.

Operating Income Adjustment No. 13 – Depreciation Expenses

Q. Please explain your adjustment to reduce depreciation expenses.

A. The adjustment is primarily attributable to RUCO's rate base adjustment No. 3 disallowing construction work in progress ("CWIP") from rate base.

RUCO agrees with the set of depreciation rates that UNS is proposing to implement on a going forward basis.

These depreciation rates were revised to reflect the Company's response to Staff Data Request 3.39. I computed test-year depreciation by multiplying RUCO's level of test-year gross plant in service by the Company's proposed depreciation rates.

As shown on Schedule RLM-8, column (N) and supporting Schedule RLM-10, my adjustment decreases adjusted test-year expenses by $142,085.

Operating Income Adjustment No. 15 – Property Tax

Q. Do you agree with UNS's methodology for computing property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

The difference in the amount I have calculated versus the Company is a result of our respective levels of recommended net plant in service. RUCO also used the assessment ratio of 23 percent, which will be valid when the authorized rates in this case become effective (January 2008).

The decreasing assessment ratios as authorized in the Arizona Revised Statues relating to property taxes states the effective rate from December 31, 2008 through December 31, 2009 to be 23 percent.

The assessment ratio will continue to decline by one-half percent each year until it reaches 20 percent on December 31, 2014.

As shown on Schedule RLM-8, column (P) and supporting Schedule RLM-11, this adjustment decreased test-year expenses by $409,902.

<u>Adjustments To Operating Expenses No. 16 – Supplemental Executive Retirement Plan</u>

Q. Please explain the basis for the adjustment you made to the Pension and Benefits operating expenses.

A. I made an adjustment to the Supplemental Executive Retirement Plan ("SERP") portion of the pension and benefits operating expenses.

Q. Please explain your adjustment to the SERP.

A. As explained in the Company's responses to Staff data request 3.83 and RUCO data request 2.06, UNS's test-year payroll loadings include the cost of a SERP. The Company's test-year operating expenses include $83,506 related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing electric service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In recent ACC Decisions did the Commissioners determine whether SERP expenses were recoverable?

A. Yes. In SWG's latest rate case (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses and it is not reasonable to place this additional burden on ratepayers. Moreover, the Commission voted on June 18, 2007 to disallow SERP in the Arizona Public Service rate case (Decision No. unavailable). Therefore, I have removed the test-year cost of the SERP from operating expenses.

As shown on Schedule RLM-8, column (Q), this adjustment decreased test-year expenses by $83,506.

Operating Income Adjustment No. 17 – Disallowance of Inappropriate and/or Unnecessary Expenses

Q. Please explain your analysis of the various operating expense accounts that result in your removal of inappropriate or unnecessary costs for the provisioning of electric service.

A After review of all the journal entries in various FERC accounts and the Company's response to a number of RUCO data requests, I determined there were numerous expenditures that were either questionable, inappropriate and/or unnecessary.

Therefore, as shown on Schedule RLM-12 and supporting workpapers attached, I have made an adjustment to remove test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of Electric service. The back-up documentation denoting each individual expense removed is recorded in Exhibit B (attached to RLM-12): FERC Account Code 921, pages 1 to 4, FERC Account 923, page 1, and FERC Account 930, pages 1 and 2.

A sampling of the 336 questionable expenses submitted by RUCO includes invoices for: 1) $746.96 for a barbeque grill; 2) $608.40 for flags; 3) $8,078.22 for refreshments; 4) $1,377.50 to various Chamber of Commerce, and 5) $1,126.25 for chartered bus tours.

As shown on Schedule RLM-8, column (R) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $73,620.

Adjustments To Operating Expenses No. 18 – Overhead Line Maintenance

Q. Please explain the basis for the adjustment you made to overhead line maintenance expense.

A. Through discovery I reviewed and analyzed four years of expenses recorded in FERC account 593 – overhead line maintenance from 2003 through 2006. My analysis indicated this expense was sufficiently volatile to recommend a test year adjustment to acknowledge the wide variation in annual costs.

Therefore, my adjusted test year expense in the instant case is the calculated four-year average of the "inflation adjusted" annual overhead line maintenance expenses for 2003 through 2006. My adjustment is necessary to normalize the test-year level of overhead maintenance expenses.

As shown on Schedule RLM-8, column (S) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $267,678.

Operating Income Adjustment No. 19 – Customer Service Cost Allocations

Q. Please provide the background for this adjustment.

A. Prior to May 1, 2005, the Call Center duties for UNS Electric were performed in-house by sixteen UNS Electric Customer Service

Representatives at seven office locations for a cost the Company estimates at $321,640 per month for those four months.

After May 1, 2005, Unisource Energy consolidated the call center operations of UNS Gas, UNS Electric and TEP at an actual allocated cost to UNS Electric of $362,013 per month for those eight months, a 12.55 percent increase in cost.

RUCO does not agree that such a dramatic increase in costs is warranted given that the integrated call center and customer service functions continue to provide approximately the same quality of service, as did in-house customer service.

Q. Please continue and provide an explanation for RUCO's adjustment to the allocated customer service costs.

A. RUCO is disallowing this expenditure because evidence provided by the Commission Consumer Services Section indicates the quality of customer service has not improved since the Unisource Energy choose to integrate similar job functions among its affiliates. The Commission Consumer Services Section Report ("Report") on UNS Electric states, in 2004, 15.3 percent of the consumer complaints were based on "quality of service" issues.

As of May 23, 2007, the report states, 2007 year-to-date, 15.3 percent of the consumer complaints are based on "quality of service" issues.

Since the Report does not demonstrate the improvements, enhancements and synergy promoted by the Company as justification for the increased expenditure has translated into increased customer satisfaction, RUCO is removing any increase in this expense until the Company provides documentation that the overall customer satisfaction level has improved.

As shown on Schedule RLM-8, column (T) and supporting Schedule RLM-14, this adjustment decreased test-year expenses by $66,797.

Adjustments To Operating Expenses No. 20 – Non-Recurring/Atypical Expenses

Q. Please explain the basis for the adjustments you made to disallow non-recurring and/or atypical operating expenses.

A. This is similar to an adjustment made in the UNS's recently filed Gas Division rate case, Docket No. G-04204A-06-0463, where the Company agreed that this is not a recurring or typical test-year expense.

Through the discovery process associated with the UNS Gas rate case, Company witness Mr. Smith and I discussed line by line the general ledger details provided by the Company in response to RUCO's data request 4.01 designated as "Procard Details – Data Request RUCO 4.01", pages 1 through 4. During that conversation I expressly asked for clarification of the entries noted as "M.A.R.C. Training (Union Training)". Mr. Smith indicated this training was a one-time only instructional session to acquaint Company personnel with working in a unionized environment. Based on that conversation with Mr. Smith, I selectively excluded only expenses denoted "M.A.R.C. Training (Union Training)" from data provided. This particular adjustment in the instant case culminated in RUCO data request 5.04. In the Company's response to this data request UNS Electric recorded test-year non-recurring expenses of $14,251 for "M.A.R.C. Training".

Therefore as shown on Schedule RLM-8, column (U), this adjustment decreased test-year expenses by $14,251.

<u>Operating Income Adjustment No. 22 – Income Tax Expense</u> – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule RLM-8, column (AC) and supporting Schedule RLM-15, this adjustment increased test-year expenses by $1,332,851.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes, it is. As shown on Schedule RLM-18, this adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 122 basis points from 9.89 to 8.67 percent to reflect current market conditions. This adjustment is fully explained in the testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX 1

Qualifications of Rodney Lane Moore

EDUCATION:	Athabasca University Bachelor's Degree in Business Administration - 1993
EXPERIENCE:	Public Utilities Analyst V Residential Utility Consumer Office Phoenix, Arizona 85007 May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.
Rio Verde Utilities, Inc	WS-02156A-00-0321
Black Mountain Gas Company	G-03703A-01-0283
Green Valley Water Company	W-02025A-01-0559
New River Utility Company	W-01737A-01-0662

Utility Company	Docket No.
Dragoon Water Company	W-01917A-01-0851
Roosevelt Lake Resort, Inc.	W-01958A-02-0283
Southwest Gas Company	G-01551A-02-0425
Arizona-American Water Company	W-01303A-02-0867 et al.
Rio Rico Utilities, Inc.	WS-02676A-03-0434
Qwest Corporation	T-01051B-03-0454
Chaparral City Water Company	W-02113A-04-0616
Southwest Gas Company	G-01551A-04-0876
Arizona-American Water Company	W-01303A-05-0405
Far West Water and Sewer Company	WS-03478A-05-0801
Gold Canyon Sewer Company	SW-02519A-06-0015
UNS Gas, Inc.	G-04204A-06-0463 et al.
Arizona-American Water Company	WS-01303A-06-0403

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

TABLE OF CONTENTS TO RUCO SCHEDULES

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 140,991,324	$ 214,613,357	$ 177,802,340	$ 128,777,882	$ 194,458,406	$ 161,618,144
2	Adjusted Operating Income (Loss)	$ 8,742,011	$ 8,742,011	$ 8,742,011	$ 10,404,382	$ 10,404,382	$ 10,404,382
3	Current Rate Of Return (Line 2 / Line 1)	6.20%	4.07%	4.92%	8.08%	5.35%	6.44%
4	Required Operating Income (Line 5 X Line 1)	$ 13,946,320	$ 13,946,320	$ 13,946,320	$ 11,169,957	$ 11,169,957	$ 11,169,957
5	Required Rate Of Return	9.89%	6.50%	7.84%	8.67%	5.74%	6.91%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 5,204,309	$ 5,204,309	$ 5,204,309	$ 765,575		$ 765,575
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 3)	1.6346	1.6346	1.6346	1.6370		1.6370
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 8,507,097	$ 8,507,097	$ 8,507,097	$ 1,253,233		$ 1,253,233
9	Adjusted Test Year Revenue			$ 158,486,890	$ 158,535,538		$ 158,535,538
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 166,993,987	$ 159,788,771		$ 159,788,771
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			5.37%	0.79%		0.79%
12	Rate Of Return On Common Equity			11.39%	9.30%		9.30%

References:
- Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
- Column (D): Schedules RLM-1, Page 2, RLM-2, RLM-7 And RLM-18
- Column (E): Schedule RLM-2
- Column (F): Average Of Column (D) + Column (E)

UNS Electric, Inc.
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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		1.0000
2	Less: Uncollectibles	Company Schedule C-3, Line 2	0.0051
3	Subtotal	Line 1 - Line 2	0.9949
4	Less: Combined Federal And State Tax Rate	Line 14	0.3840
5	Subtotal	Line 3 - Line 4	0.6109
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6370**
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		1.0000
8	Arizona State Income Tax Rate		0.0697
9	Federal Taxable Income	Line 7 - Line 8	0.9303
10	Applicable Federal Income Tax Rate		0.3400
11	Effective Federal Income Tax Rate	Line 9 X Line 10	0.3163
12	Subtotal	Line 8 + Line 11	0.3860
13	Revenue Less Uncollectibles	Line 3	0.9949
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	0.3840

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 390,513,651	$ 612,326,062	$ 501,419,857	156.80%	$ 379,752,198	$ 595,452,086	$ 487,602,142
2	Accumulated Depreciation	(159,524,693)	(257,585,628)	(208,555,161)	161.47%	(161,819,805)	(261,291,561)	(211,555,683)
3	Net Utility Plant In Service	$ 230,988,958	$ 354,740,434	$ 292,864,696		$ 217,932,393	$ 334,160,525	$ 276,046,459
4	Citizens Acquisition Discount	$ (93,273,341)	$ (150,061,415)	$ (121,667,378)	160.88%	$ (93,273,341)	$ (150,061,415)	$ (121,667,378)
5	Accumulated Amortization	11,224,066	18,123,969	14,674,018	161.47%	11,224,066	18,123,969	14,674,018
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ (131,937,446)	$ (106,993,361)		$ (82,049,275)	$ (131,937,446)	$ (106,993,361)
7	Total Net Utility Plant	$ 148,939,683	$ 222,802,988	$ 185,871,336		$ 135,883,118	$ 202,223,079	$ 169,053,099
	Deductions:							
8	Cust. Advances For Const.	$ (8,692,444)	$ (9,559,141)	$ (9,125,793)	109.97%	$ (8,692,444)	$ (9,559,141)	$ (9,125,793)
9	Customer Deposits	(3,778,419)	(3,778,419)	(3,778,419)	100.00%	(3,778,419)	(3,778,419)	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	1,780,258	1,467,546	154.16%	382,701	589,961	486,331
11	Total Deductions	$ (11,316,030)	$ (11,557,302)	$ (11,436,666)		$ (12,088,162)	$ (12,747,599)	$ (12,417,880)
12	Allowance - Working Capital	$ 3,367,671	$ 3,367,671	$ 3,367,671	100.00%	$ 4,982,926	$ 4,982,926	$ 4,982,926
13	Regulatory Assets	$ -	$ -	$ -		$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -		$ -	$ -	$ -
15	TOTAL TEST YEAR RATE BASE	$ 140,991,324	$ 214,613,357	$ 177,802,341		$ 128,777,882	$ 194,458,406	$ 161,618,144

References:
- Columns (A) (B) (C): Company Schedule B-1
- Column (D): Column (B) / Column (A)
- Column (E): Schedule RLM-3, Column (C)
- Column (F): Column (D) X Column (E)
- Column (G): Average Of Column (E) + Column (F)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

ORIGINAL COST RATE BASE STATEMENT

LINE NO.	DESCRIPTION		(A) COMPANY FILED AS OCRB		(B) RUCO ADJUSTMENTS		(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$	390,513,651	$	(10,761,453)	$	379,752,198
2	Accumulated Depreciation		(159,524,693)		(2,295,112)		(161,819,805)
3	Net Utility Plant In Service	$	230,988,958	$	(13,056,565)	$	217,932,393
4	Citizens Acquisition Discount	$	(93,273,341)	$	-	$	(93,273,341)
5	Accumulated Amortization		11,224,066		-		11,224,066
6	Net Citizens Acq. Disc.	$	(82,049,275)	$	-	$	(82,049,275)
7	Total Net Utility Plant	$	148,939,683	$	(13,056,565)	$	135,883,118
	Deductions:						
8	Cust. Advances For Const.	$	(8,692,444)	$	-	$	(8,692,444)
9	Customer Deposits		(3,778,419)		-		(3,778,419)
10	Acc. Deferred Income Taxes		1,154,833		(772,132)		382,701
11	Total Deductions	$	(11,316,030)	$	(772,132)	$	(12,088,162)
12	Allowance - Working Capital	$	3,367,671	$	1,615,255	$	4,982,926
13	Regulatory Assets	$	-	$	-	$	-
14	Regulatory Liability	$	-	$	-	$	-
15	TOTAL OCRB	$	140,991,324	$	(12,213,442)	$	128,777,882

References:
- Column (A): - Company Schedule B-2
- Column (B): - RUCO Adjustments As Per RLM-4, Columns (B) Thru (G)
- Column (C): - Sum Of Columns (A) And (B)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

SUMMARY OF ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) INTENTIONALLY LEFT BLANK	(C) RUCO ADJUSTMENT NO. 2	(D) RUCO ADJUSTMENT NO. 3	(E) RUCO ADJUSTMENT NO. 4	(F) RUCO ADJUSTMENT NO. 5	(G) RUCO ADJUSTMENT NO. 6	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 390,513,651	$ -	$ -	$ (10,761,453)	$ -	$ -	$ -	$ 379,752,198
2	Accumulated Depreciation	(159,524,693)	-	(2,295,112)	-	-	-	-	(161,819,805)
3	Net Utility Plant In Service	$ 230,988,958	$ -	$ (2,295,112)	$ (10,761,453)	$ -	$ -	$ -	$ 217,932,393
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ -	$ -	$ -	$ -	$ -	$ (93,273,341)
5	Accumulated Amortization	11,224,066	-	-	-	-	-	-	11,224,066
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ -	$ -	$ -	$ -	$ -	$ -	$ (82,049,275)
7	Total Net Utility Plant	$ 148,939,683	$ -	$ (2,295,112)	$ (10,761,453)	$ -	$ -	$ -	$ 135,883,118
	Deductions:								
8	Cust. Advances For Const.	$ (8,692,444)	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,692,444)
9	Customer Deposits	(3,778,419)	-	-	-	-	-	-	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	-	-	-	(888,390)	116,258	-	382,701
11	Total Deductions	$ (11,316,030)	$ -	$ -	$ -	$ (888,390)	$ 116,258	$ -	$ (12,088,162)
12	Allowance - Working Capital	$ 3,367,671	$ -	$ -	$ -	$ -	$ -	$ 1,615,255	$ 4,982,926
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TOTAL OCRB	$ 140,991,324	$ -	$ (2,295,112)	$ (10,761,453)	$ (888,390)	$ 116,258	$ 1,615,255	$ 128,777,882

References:
Column (A): - Company Schedule B-2
Column (B): - Intentionally Left Blank
Column (C): - Adjustment No. 2 RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-5, Page 6, Line 46)
Column (D): - Adjustment No. 3 RUCO Adjustment To Remove CWIP From Test-Year Rate Base (See Testimony, MDC)
Column (E): - Adjustment No. 4 RUCO Adjustment To Remove ADIT Related To CIAC From Test-Year Rate Base (See Testimony, MDC)
Column (F): - Adjustment No. 5 RUCO Adjustment To Adjusted ADIT Related To A & G Capitalization From Test-Year Rate Base (See Testimony, MDC)
Column (G): - Adjustment No. 6 Allowance For Working Capital (See MDC-2)
Column (H): - Sum Of Columns (A) Through (G)

TEST YEAR PLANT SCHEDULES
YEAR ENDED DECEMBER 31, 2002

	,CT NO.	ACCOUNT NAME	(A) DEP. RATES AS FILING	(B) PROPOSED DEP. RATES	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
	302	Franchises & Consents	0.00%	4.00%	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	0.00%	6.59%	-	-	4,219,098	-	(267,350)	3,951,748
3		Total Intangible Plant			$ -	$ -	$ 4,231,006	$ -	$ (267,350)	$ 3,963,656
		Other Production								
4	340	Land & Rights	0.00%	0.00%	$ -	$ -	$ 789,651	$ -	$ -	$ 789,651
5	341	Structures & Improvements	1.38%	2.07%	-	-	619,244	(29,957)	(341,982)	277,262
6	342	Fuel Holders, Producers & Acc.	2.42%	2.51%	-	-	631,364	(30,543)	(75,204)	556,160
7	343	Prime Movers	2.34%	2.53%	-	-	8,684,079	(420,103)	(2,028,185)	6,655,895
8	344	Generators	0.67%	2.33%	-	-	2,309,132	(111,707)	(208,430)	2,100,702
9	345	Accessory Electric Equipment	2.20%	2.35%	-	-	1,685,197	(81,523)	(339,420)	1,345,776
10	346	Misc. Power Plant Equipment	1.87%	2.64%	-	-	493,979	(23,897)	(44,154)	449,824
11		Total Other Production			$ -	$ -	$ 15,212,646	$ (697,730)	$ (3,037,375)	$ 12,175,271
		Transmission :								
12	350	Land & Rights	0.00%	0.55%	$ -	$ -	$ 1,249,979	$ -	$ -	$ 1,249,979
13	352	Structures & Improvements	3.77%	3.13%	-	-	346,422	(16,759)	(124,730)	221,692
14	353	Station Equipment	2.92%	3.15%	-	-	16,025,096	(775,234)	(5,012,905)	11,012,191
15	354	Towers & Fixtures	2.87%	5.03%	-	-	290,612	(14,059)	(86,121)	204,491
16	355	Poles & Fixtures	5.77%	4.48%	-	-	9,740,328	(471,200)	(4,512,361)	5,227,967
17	356	Overhead Conductors & Devices	2.71%	2.66%	-	-	9,355,192	(452,569)	(3,424,562)	5,930,630
18	359	Roads & Trails	2.01%	2.02%	-	-	183,860	(8,894)	(62,159)	121,701
19		Total Transmission Plant			$ -	$ -	$ 37,191,489	$ (1,738,715)	$ (13,222,838)	$ 23,968,651
		Distribution:								
20	360	Land & Rights	0.00%	1.17%	$ -	$ -	$ 1,109,275	$ -	$ -	$ 1,109,275
21	361	Structures & Improvements	3.20%	2.96%	-	-	3,398,247	(164,394)	(497,879)	2,900,368
22	362	Station Equipment	4.82%	4.09%	-	-	27,821,016	(1,345,876)	(10,245,496)	17,575,520
23	364	Poles, Towers & Fixtures	4.23%	4.14%	-	-	67,853,801	(3,282,512)	(26,953,218)	40,900,584
24	365	Overhead Conductors & Devices	4.36%	4.13%	-	-	41,912,117	(2,027,551)	(17,231,020)	24,681,097
25	366	Underground Conduit	4.28%	3.79%	-	-	10,705,488	(517,891)	(2,603,610)	8,101,878
26	367	UG Conductors & Devices	5.36%	4.40%	-	-	16,824,452	(813,904)	(6,701,043)	10,123,409
27	368	Line Transformers	4.93%	4.63%	-	-	35,642,570	(1,724,254)	(16,240,337)	19,402,233
28	369	Services	4.23%	3.76%	-	-	10,208,172	(493,833)	(3,062,392)	7,145,781
29	370	Meters	3.25%	3.11%	-	-	7,565,593	(365,995)	(2,086,182)	5,479,411
30	373	Street Lights & Signal Systems	4.55%	4.04%	-	-	2,996,693	(144,969)	(811,037)	2,185,656
31		Total Distribution Plant			$ -	$ -	$ 226,037,423	$ (10,881,179)	$ (86,432,213)	$ 139,605,210
		General:								
32	389	Land & Rights	0.00%	0.00%	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	2.89%	2.65%	-	-	1,832,359	(88,643)	(637,253)	1,195,106
34	391	Office Furniture & Equipment	3.72%	9.11%	-	-	3,463,513	(167,552)	(831,659)	2,631,853
35	392	Transportation Equipment	25.00%	14.43%	-	-	8,416,254	(407,147)	(5,994,712)	2,421,542
36	393	Stores Equipment	2.62%	3.03%	-	-	107,310	(5,191)	(46,575)	60,736
37	394	Tools, Shop And Garage Equip.	3.02%	3.45%	-	-	1,606,644	(77,723)	(259,335)	1,347,309
38	395	Laboratory Equipment	2.41%	2.50%	-	-	935,958	(45,278)	(148,205)	787,753
39	396	Power Operated Equipment	3.33%	6.92%	-	-	644,863	(31,196)	(382,604)	262,260
40	397	Communication Equipment	4.13%	4.35%	-	-	959,853	(46,434)	(193,156)	766,698
41	398	Miscellaneous Equipment	5.45%	5.56%	-	-	129,333	(6,257)	(77,991)	51,342
42		Total General Plant			$ -	$ -	$ 18,153,669	$ (875,421)	$ (8,571,491)	$ 9,582,178
43		Rounding					$ 99			
44		TOTAL PLANT			$ -	$ -	$ 300,826,332	$ (14,193,045)	$ (111,531,267)	$ 189,294,966

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Requests
Columns (F) (G): RUCO Workpapers - Exhibit (A)
Column (H): Column (E) + Column (G)

TEST YEAR PLANT SCHEDULES - CONT'D
PORTION OF YEAR FROM DECEMBER 31, 2002 ENDED AUGUST 11, 2003

	.CT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) COMPANY RECLASSIFIED PER RUCO DR 5.03	(D) NET PLANT ADDITIONS	(E) PLANT RETIRM'TS	(F) TOTAL PLANT VALUE	(G) ACCURAL DEPRECIATION	(H) ACCUMULATED DEPRECIATION	(I) NET PLANT VALUE
		Intangible:									
.	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	1,145,223	1,145,223	-	5,364,321	-	(267,350)	5,096,971
3		Total Intangible Plant	$ -	$ -	$ 1,145,223	$ 1,145,223	$ -	$ 5,376,229	$ -	$ (267,350)	$ 5,108,879
		Other Production									
4	340	Land & Rights	$ -	$ (23,777)	$ -	$ (23,777)	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	-	619,244	(5,221)	(347,203)	272,041
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	-	631,364	(9,335)	(84,539)	546,825
7	343	Prime Movers	-	-	-	-	-	8,684,079	(124,151)	(2,152,336)	6,531,743
8	344	Generators	-	-	-	-	-	2,309,132	(9,452)	(217,882)	2,091,250
9	345	Accessory Electric Equipment	-	-	-	-	-	1,685,197	(22,651)	(362,071)	1,323,126
10	346	Misc. Power Plant Equipment	-	-	-	-	-	493,979	(5,644)	(49,798)	444,181
11		Total Other Production	$ -	$ (23,777)	$ -	$ (23,777)	$ -	$ 15,188,868	$ (176,454)	$ (3,213,829)	$ 11,975,039
		Transmission :									
12	350	Land & Rights	$ 5,904	$ 22,107	$ -	$ 28,011	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	(141,819)	(364)	(142,183)	(12,571)	191,668	(6,197)	(130,927)	60,741
14	353	Station Equipment	-	-	-	-	-	16,025,096	(285,888)	(5,298,793)	10,726,303
15	354	Towers & Fixtures	231,213	-	-	231,213	-	521,825	(7,123)	(93,244)	428,581
16	355	Poles & Fixtures	919,649	-	-	919,649	-	10,659,976	(359,579)	(4,871,940)	5,788,036
17	356	Overhead Conductors & Devices	979,048	-	-	979,048	(91)	10,334,150	(162,998)	(3,587,560)	6,746,590
18	359	Roads & Trails	-	-	-	-	-	183,860	(2,258)	(64,417)	119,443
19		Total Transmission Plant	$ 2,135,815	$ (119,711)	$ (364)	$ 2,015,739	$ (12,662)	$ 39,194,566	$ (824,043)	$ (14,046,881)	$ 25,147,685
		Distribution:									
20	360	Land & Rights	$ 55,667	$ 1,670	$ -	$ 57,336	$ -	$ 1,166,611	$ -	$ -	$ 1,166,611
21	361	Structures & Improvements	-	-	-	-	-	3,398,247	(66,438)	(564,317)	2,833,930
22	362	Station Equipment	638,721	120,846	1,218	760,785	-	28,581,801	(830,481)	(11,075,977)	17,505,824
23	364	Poles, Towers & Fixtures	2,472,439	(500,777)	65,859	2,037,521	(45,961)	69,845,361	(1,779,318)	(28,732,536)	41,112,825
24	365	Overhead Conductors & Devices	1,419,377	(348,841)	(70,710)	999,826	(30,597)	42,881,347	(1,129,356)	(18,360,376)	24,520,971
25	366	Underground Conduit	373,437	(5,566)	(13,996)	353,875	(151)	11,059,212	(284,563)	(2,888,173)	8,171,039
26	367	UG Conductors & Devices	811,972	(272,614)	14,229	553,587	(12,073)	17,365,966	(559,824)	(7,260,867)	10,105,099
27	368	Line Transformers	1,266,147	(10,703)	(1,507,227)	(251,783)	(95,472)	35,295,314	(1,068,334)	(17,308,671)	17,986,643
28	369	Services	621,062	(48,057)	-	573,004	(169,668)	10,611,508	(269,027)	(3,331,419)	7,280,089
29	370	Meters	235,131	-	4,975	240,106	(13,949)	7,791,750	(152,469)	(2,238,651)	5,553,099
30	373	Street Lights & Signal Systems	89,652	-	-	89,652	(15,667)	3,070,678	(84,332)	(895,369)	2,175,309
31		Total Distribution Plant	$ 7,983,604	$ (1,064,042)	$ (1,505,652)	$ 5,413,910	$ (383,538)	$ 231,067,795	$ (6,224,143)	$ (92,656,356)	$ 138,411,439
		General:									
32	389	Land & Rights	$ -	$ -	$ 0	$ 0	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	-	20,973	(39,986)	(19,013)	-	1,813,346	(32,186)	(669,439)	1,143,907
34	391	Office Furniture & Equipment	8,606	-	(1,161,087)	(1,152,482)	(814)	2,310,217	(65,612)	(897,271)	1,412,946
35	392	Transportation Equipment	-	-	(899,227)	(899,227)	(91,553)	7,425,475	(1,209,831)	(7,204,543)	220,932
36	393	Stores Equipment	2,910	-	12,651	15,561	-	122,871	(1,842)	(48,417)	74,454
37	394	Tools, Shop And Garage Equip.	36,004	-	696,713	732,718	-	2,339,362	(36,404)	(295,739)	2,043,623
38	395	Laboratory Equipment	-	-	(127,850)	(127,850)	-	808,108	(12,840)	(161,045)	647,063
39	396	Power Operated Equipment	2,807	-	320,587	323,395	-	968,258	(16,409)	(399,013)	569,245
40	397	Communication Equipment	16,501	-	70,101	86,603	-	1,046,456	(25,312)	(218,468)	827,988
41	398	Miscellaneous Equipment	-	-	(14,690)	(14,690)	-	114,643	(4,062)	(82,053)	32,590
42		Total General Plant	$ 66,828	$ 20,973	$ (1,142,788)	$ (1,054,986)	$ (92,367)	$ 17,006,316	$ (1,404,497)	$ (9,975,988)	$ 7,030,328
43		TOTAL PLANT	$ 10,186,247	$ (1,186,558)	$ (1,503,581)	$ 7,496,108	$ (488,566)	$ 307,833,775	$ (8,629,137)	$ (120,160,404)	$ 187,673,371

References:
Columns (A) (B) (C) (D) (E) (F) (H): Company Response To RUCO Data Requests
Column (G): [(Cl. (D) + Cl. (E)) X RLM-5, Pg 1, Cl. (A) X 223/365 Days X 1/2 yr. conv.] + [(RLM-5, Pg 1, Cl. (E) + Cl. (E)) X RLM-5, Pg 1, Cl. (A) X 142/365 Days]
Column (I): Column (F) + Column (H)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

TEST YEAR PLANT SCHEDULES - CONT'D
PORTION OF YEAR FROM AUGUST 11 ENDED DECEMBER 31, 2003

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJUSTMENTS	(C) NET PLANT ADDITIONS	(D) PLANT RETIREMENTS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	-	-	5,364,321	-	(267,350)	5,096,971
3		Total Intangible Plant	$ -	$ -	$ -	$ -	$ 5,376,229	$ -	$ (267,350)	$ 5,108,879
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	619,244	(3,325)	(350,528)	268,717
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	631,364	(5,944)	(90,483)	540,881
7	343	Prime Movers	-	-	-	-	8,684,079	(79,056)	(2,231,392)	6,452,687
8	344	Generators	-	-	-	-	2,309,132	(6,019)	(223,901)	2,085,231
9	345	Accessory Electric Equipment	-	-	-	-	1,685,197	(14,423)	(376,494)	1,308,702
10	346	Misc. Power Plant Equipment	-	-	-	-	493,979	(3,594)	(53,392)	440,587
11		Total Other Production	$ -	$ -	$ -	$ -	$ 15,188,868	$ (112,361)	$ (3,326,190)	$ 11,862,679
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(2,811)	(133,738)	57,930
14	353	Station Equipment	-	-	-	-	16,025,096	(182,045)	(5,480,838)	10,544,258
15	354	Towers & Fixtures	-	-	-	-	521,825	(5,826)	(99,070)	422,755
16	355	Poles & Fixtures	-	-	-	-	10,659,976	(239,292)	(5,111,232)	5,548,745
17	356	Overhead Conductors & Devices	-	-	-	-	10,334,150	(108,953)	(3,696,513)	6,637,637
18	359	Roads & Trails	-	-	-	-	183,860	(1,438)	(65,855)	118,005
19		Total Transmission Plant	$ -	$ -	$ -	$ -	$ 39,194,566	$ (540,365)	$ (14,587,246)	$ 24,607,320
		Distribution:								
20	360	Land & Rights	$ -	$ -	$ -	$ -	$ 1,166,611	$ -	$ -	$ 1,166,611
21	361	Structures & Improvements	-	-	-	-	3,398,247	(42,306)	(606,623)	2,791,624
22	362	Station Equipment	-	-	-	-	28,581,801	(535,960)	(11,611,937)	16,969,864
23	364	Poles, Towers & Fixtures	-	-	-	-	69,845,361	(1,149,406)	(29,881,942)	39,963,419
24	365	Overhead Conductors & Devices	-	-	-	-	42,881,347	(727,362)	(19,087,738)	23,793,609
25	366	Underground Conduit	-	-	-	-	11,059,212	(184,146)	(3,072,319)	7,986,893
26	367	UG Conductors & Devices	-	-	-	-	17,365,966	(362,126)	(7,622,993)	9,742,973
27	368	Line Transformers	-	-	-	-	35,295,314	(676,954)	(17,985,625)	17,309,689
28	369	Services	-	-	-	-	10,611,508	(174,628)	(3,506,047)	7,105,462
29	370	Meters	-	-	-	-	7,791,750	(98,518)	(2,337,169)	5,454,581
30	373	Street Lights & Signal Systems	-	-	-	-	3,070,678	(54,355)	(949,724)	2,120,954
31		Total Distribution Plant	$ -	$ -	$ -	$ -	$ 231,067,795	$ (4,005,760)	$ (96,662,116)	$ 134,405,679
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	-	-	-	-	1,813,346	(20,388)	(689,827)	1,123,519
34	391	Office Furniture & Equipment	-	-	-	-	2,310,217	(33,434)	(930,705)	1,379,512
35	392	Transportation Equipment	-	-	-	-	7,425,475	(722,204)	(7,926,747)	(501,272)
36	393	Stores Equipment	-	-	-	-	122,871	(1,252)	(49,669)	73,202
37	394	Tools, Shop And Garage Equip.	-	-	-	-	2,339,362	(27,485)	(323,224)	2,016,138
38	395	Laboratory Equipment	-	-	-	-	808,108	(7,577)	(168,622)	639,486
39	396	Power Operated Equipment	-	-	-	-	968,258	(12,544)	(411,557)	556,701
40	397	Communication Equipment	-	-	-	-	1,046,456	(16,814)	(235,282)	811,174
41	398	Miscellaneous Equipment	-	-	-	-	114,643	(2,431)	(84,484)	30,159
42		Total General Plant	$ -	$ -	$ -	$ -	$ 17,006,316	$ (844,129)	(10,820,117)	$ 6,186,199
		Rounding					$ (1)			
43		TOTAL PLANT	$ -	$ -	$ -	$ -	$ 307,833,774	$ (5,502,615)	(125,663,019)	$ 182,170,757

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Requests
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 2, Cl. (F) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 2, Column (H) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2004

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	5,505,174	-	5,505,174	-	10,869,495	-	(267,350)	10,602,145
3		Total Intangible Plant	$ 5,505,174	$ -	$ 5,505,174	$ -	$ 10,881,403	$ -	$ (267,350)	$ 10,614,053
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	619,244	(8,546)	(359,073)	260,171
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	631,364	(15,279)	(105,762)	525,602
7	343	Prime Movers	-	-	-	-	8,684,079	(203,207)	(2,434,600)	6,249,480
8	344	Generators	-	-	-	-	2,309,132	(15,471)	(239,372)	2,069,759
9	345	Accessory Electric Equipment	-	-	-	-	1,685,197	(37,074)	(413,569)	1,271,628
10	346	Misc. Power Plant Equipment	-	-	-	-	493,979	(9,237)	(62,629)	431,350
11		Total Other Production	$ -	$ -	$ -	$ -	$ 15,188,868	$ (288,815)	$ (3,615,005)	$ 11,573,864
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(7,226)	(140,964)	50,704
14	353	Station Equipment	1,889,666	(183,168)	1,706,498	-	17,731,594	(492,848)	(5,973,686)	11,757,909
15	354	Towers & Fixtures	-	-	-	-	521,825	(14,976)	(114,047)	407,778
16	355	Poles & Fixtures	-	-	-	-	10,659,976	(615,081)	(5,726,312)	4,933,664
17	356	Overhead Conductors & Devices	-	-	-	-	10,334,150	(280,055)	(3,976,569)	6,357,581
18	359	Roads & Trails	-	-	-	-	183,860	(3,696)	(69,550)	114,310
19		Total Transmission Plant	$ 1,889,666	$ (183,168)	$ 1,706,498	$ -	$ 40,901,064	$ (1,413,882)	$ (16,001,128)	$ 24,899,936
		Distribution:								
20	360	Land & Rights	$ -	$ -	$ -	$ -	$ 1,166,611	$ -	$ -	$ 1,166,611
21	361	Structures & Improvements	53,763	-	53,763	-	3,452,010	(109,604)	(716,227)	2,735,783
22	362	Station Equipment	459,333	(179,336)	279,997	-	28,861,798	(1,384,391)	(12,996,327)	15,865,471
23	364	Poles, Towers & Fixtures	-	(69,495)	(69,495)	-	69,775,866	(2,952,989)	(32,834,931)	36,940,935
24	365	Overhead Conductors & Devices	9,138,146	-	9,138,146	-	52,019,493	(2,068,838)	(21,156,576)	30,862,917
25	366	Underground Conduit	33,854	-	33,854	-	11,093,066	(474,059)	(3,546,378)	7,546,688
26	367	UG Conductors & Devices	-	-	-	-	17,365,966	(930,816)	(8,553,808)	8,812,158
27	368	Line Transformers	336,011	431,999	768,010	-	36,063,324	(1,758,990)	(19,744,616)	16,318,708
28	369	Services	2,361,696	-	2,361,696	-	12,973,204	(498,817)	(4,004,863)	8,968,341
29	370	Meters	58,299	-	58,299	-	7,850,049	(254,179)	(2,591,348)	5,258,701
30	373	Street Lights & Signal Systems	15,271	-	15,271	-	3,085,949	(140,063)	(1,089,787)	1,996,162
31		Total Distribution Plant	$ 12,456,373	$ 183,168	$ 12,639,541	$ -	$ 243,707,336	$ (10,572,746)	$ (107,234,862)	$ 136,472,474
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	110,131	-	110,131	-	1,923,477	(53,997)	(743,824)	1,179,653
34	391	Office Furniture & Equipment	865,711	-	865,711	-	3,175,928	(102,042)	(1,032,748)	2,143,180
35	392	Transportation Equipment	140,998	-	140,998	-	7,566,473	(1,873,994)	(9,800,740)	(2,234,267)
36	393	Stores Equipment	-	-	-	-	122,871	(3,219)	(52,889)	69,982
37	394	Tools, Shop And Garage Equip.	233,812	-	233,812	-	2,573,174	(74,179)	(397,404)	2,175,770
38	395	Laboratory Equipment	-	-	-	-	808,108	(19,475)	(188,097)	620,011
39	396	Power Operated Equipment	-	-	-	-	968,258	(32,243)	(443,800)	524,458
40	397	Communication Equipment	46,632	-	46,632	-	1,093,088	(44,182)	(279,463)	813,625
41	398	Miscellaneous Equipment	-	-	-	-	114,643	(6,248)	(90,732)	23,911
42		Total General Plant	$ 1,397,284	$ -	$ 1,397,284	$ -	$ 18,403,600	$ (2,209,579)	$ (13,029,696)	$ 5,373,904
43		TOTAL PLANT	$ 21,248,497	$ -	$ 21,248,497	$ -	$ 329,082,272	$ (14,485,022)	$ (140,148,041)	$ 188,934,231

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Request 1.08
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 3, Cl. (E) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 3, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2005

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	1,417,769	(1,679,528)	(261,759)	-	10,607,736	-	(267,350)	10,340,386
3		Total Intangible Plant	$ 1,417,769	$ (1,679,528)	$ (261,759)	$ -	$ 10,619,644	$ -	$ (267,350)	$ 10,352,294
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	619,244	(8,546)	(367,619)	251,626
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	631,364	(15,279)	(121,041)	510,323
7	343	Prime Movers	-	-	-	-	8,684,079	(203,207)	(2,637,807)	6,046,272
8	344	Generators	-	-	-	-	2,309,132	(15,471)	(254,843)	2,054,288
9	345	Accessory Electric Equipment	-	-	-	-	1,685,197	(37,074)	(450,643)	1,234,553
10	346	Misc. Power Plant Equipment	-	-	-	-	493,979	(9,237)	(71,867)	422,112
11		Total Other Production	$ -	$ -	$ -	$ -	$ 15,188,868	$ (288,815)	$ (3,903,820)	$ 11,285,049
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(7,226)	(148,190)	43,478
14	353	Station Equipment	(73,949)	-	(73,949)	-	17,657,645	(516,683)	(6,490,369)	11,167,277
15	354	Towers & Fixtures	-	-	-	-	521,825	(14,976)	(129,023)	392,802
16	355	Poles & Fixtures	1,625,193	-	1,625,193	-	12,285,169	(661,967)	(6,388,280)	5,896,890
17	356	Overhead Conductors & Devices	911,507	-	911,507	-	11,245,657	(292,406)	(4,268,975)	6,976,682
18	359	Roads & Trails	-	-	-	-	183,860	(3,696)	(73,246)	110,614
19		Total Transmission Plant	$ 2,462,751	$ -	$ 2,462,751	$ -	$ 43,363,815	$ (1,496,955)	$ (17,498,082)	$ 25,865,733
		Distribution:								
20	360	Land & Rights	$ 29,790	$ -	$ 29,790	$ -	$ 1,196,401	$ -	$ -	$ 1,196,401
21	361	Structures & Improvements	(53,763)	-	(53,763)	-	3,398,247	(109,604)	(825,831)	2,572,415
22	362	Station Equipment	(459,332)	-	(459,332)	-	28,402,466	(1,380,069)	(14,376,396)	14,026,070
23	364	Poles, Towers & Fixtures	5,895,620	-	5,895,620	(74,604)	75,596,882	(3,074,634)	(35,834,960)	39,761,922
24	365	Overhead Conductors & Devices	(3,597,875)	-	(3,597,875)	(110,848)	48,310,770	(2,187,200)	(23,232,928)	25,077,842
25	366	Underground Conduit	1,034,159	-	1,034,159	(358)	12,126,867	(496,907)	(4,042,927)	8,083,940
26	367	UG Conductors & Devices	5,683,664	-	5,683,664	(73,238)	22,976,392	(1,081,175)	(9,561,746)	13,414,646
27	368	Line Transformers	10,062,532	-	10,062,532	(467,431)	45,658,425	(2,014,441)	(21,291,626)	24,366,799
28	369	Services	(2,360,169)	-	(2,360,169)	-	10,613,035	(498,849)	(4,503,712)	6,109,323
29	370	Meters	1,518,174	-	1,518,174	-	9,368,223	(279,797)	(2,871,145)	6,497,078
30	373	Street Lights & Signal Systems	683,780	-	683,780	-	3,769,729	(155,967)	(1,245,754)	2,523,975
31		Total Distribution Plant	$ 18,436,580	$ -	$ 18,436,580	$ (726,479)	$ 261,417,437	$ (11,278,642)	$ (117,787,025)	$ 143,630,413
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	522,261	-	522,261	-	2,445,738	(63,135)	(806,959)	1,638,779
34	391	Office Furniture & Equipment	(9,802)	-	(9,802)	-	3,166,126	(117,962)	(1,150,710)	2,015,416
35	392	Transportation Equipment	1,313,645	-	1,313,645	(1,231,497)	7,648,621	(1,901,887)	(10,471,130)	(2,822,509)
36	393	Stores Equipment	-	-	-	-	122,871	(3,219)	(56,108)	66,763
37	394	Tools, Shop And Garage Equip.	(181,419)	-	(181,419)	-	2,391,755	(74,970)	(472,374)	1,919,381
38	395	Laboratory Equipment	-	-	-	-	808,108	(19,475)	(207,573)	600,535
39	396	Power Operated Equipment	-	-	-	-	968,258	(32,243)	(476,043)	492,215
40	397	Communication Equipment	1,298,628	-	1,298,628	-	2,391,716	(71,961)	(351,425)	2,040,291
41	398	Miscellaneous Equipment	-	-	-	-	114,643	(6,248)	(96,980)	17,663
42		Total General Plant	$ 2,943,313	$ -	$ 2,943,313	$ (1,231,497)	$ 20,115,416	$ (2,291,101)	$ (14,089,301)	$ 6,026,116
43		TOTAL PLANT	$ 25,260,413	$ (1,679,528)	$ 23,580,885	$ (1,957,976)	$ 350,705,181	$ (15,355,513)	$ (153,545,578)	$ 197,159,604

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Request 1.08
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 4, Cl. (E) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 4, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

**RATE BASE ADJUSTMENT NO. 2 - REMOVE TEST-YEAR ACCUMULATED DEPRECIATION
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED JUNE 30, 2006**

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	(85,082)	-	10,522,654	-	(267,350)	10,255,304
3		Total Intangible Plant	$ -	$ -	$ (85,082)	$ -	$ 10,534,562	$ -	$ (267,350)	$ 10,267,212
		Other Production								
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ -	$ 765,874
5	341	Structures & Improvements	-	-	522,252	-	1,141,496	(6,025)	(373,643)	767,853
6	342	Fuel Holders, Producers & Acc.	-	-	532,473	-	1,163,837	(10,772)	(131,813)	1,032,024
7	343	Prime Movers	-	-	6,729,891	-	15,413,970	(139,815)	(2,777,622)	12,636,349
8	344	Generators	-	-	2,541,445	-	4,850,577	(11,894)	(266,737)	4,583,839
9	345	Accessory Electric Equipment	-	-	1,421,243	-	3,106,440	(26,137)	(476,780)	2,629,659
10	346	Misc. Power Plant Equipment	-	-	416,606	-	910,585	(6,512)	(78,379)	832,206
11		Total Other Production	$ -	$ -	$ 12,163,910	$ -	$ 27,352,778	$ (201,155)	$ (4,104,975)	$ 23,247,804
		Transmission :								
12	350	Land & Rights	$ -	$ -	$ -	$ -	$ 1,277,990	$ -	$ -	$ 1,277,990
13	352	Structures & Improvements	-	-	-	-	191,668	(3,583)	(151,773)	39,895
14	353	Station Equipment	-	-	91,728	-	17,749,373	(256,347)	(6,746,715)	11,002,658
15	354	Towers & Fixtures	-	-	-	-	521,825	(7,427)	(136,450)	385,375
16	355	Poles & Fixtures	-	-	(14,814)	-	12,270,355	(351,302)	(6,739,582)	5,530,774
17	356	Overhead Conductors & Devices	-	-	(8,084)	-	11,237,573	(151,072)	(4,420,047)	6,817,526
18	359	Roads & Trails	-	-	-	-	183,860	(1,833)	(75,079)	108,782
19		Total Transmission Plant	$ -	$ -	$ 68,830	$ -	$ 43,432,645	$ (771,563)	$ (18,269,646)	$ 25,163,000
		Distribution:								
20	360	Land & Rights	$ -	$ -	$ 41,484	$ -	$ 1,237,885	$ -	$ -	$ 1,237,885
21	361	Structures & Improvements	-	-	681,251	-	4,079,498	(59,330)	(885,161)	3,194,336
22	362	Station Equipment	-	-	4,546,004	-	32,948,470	(733,203)	(15,109,599)	17,838,871
23	364	Poles, Towers & Fixtures	-	-	687,821	-	76,284,703	(1,592,947)	(37,427,907)	38,856,796
24	365	Overhead Conductors & Devices	-	-	1,409,966	-	49,720,736	(1,059,761)	(24,292,689)	25,428,047
25	366	Underground Conduit	-	-	474,196	-	12,601,063	(262,414)	(4,305,341)	8,295,722
26	367	UG Conductors & Devices	-	-	4,282,615	-	27,259,007	(667,622)	(10,229,367)	17,029,640
27	368	Line Transformers	-	-	1,840,762	-	47,499,187	(1,138,731)	(22,430,357)	25,068,830
28	369	Services	-	-	82,528	-	10,695,563	(223,486)	(4,727,199)	5,968,365
29	370	Meters	-	-	428,519	-	9,796,742	(154,435)	(3,025,580)	6,771,162
30	373	Street Lights & Signal Systems	-	-	41,342	-	3,811,071	(85,523)	(1,331,277)	2,479,794
31		Total Distribution Plant	$ -	$ -	$ 14,516,488	$ -	$ 275,933,925	$ (5,977,451)	$ (123,764,476)	$ 152,169,449
		General:								
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ -	$ 57,580
33	390	Structures & Improvements	-	-	(593,232)	-	1,852,506	(30,800)	(837,759)	1,014,747
34	391	Office Furniture & Equipment	-	-	54,363	-	3,220,489	(58,907)	(1,209,617)	2,010,872
35	392	Transportation Equipment	-	-	2,691,785	-	10,340,406	(1,115,073)	(11,586,203)	(1,245,797)
36	393	Stores Equipment	-	-	-	-	122,871	(1,596)	(57,704)	65,167
37	394	Tools, Shop And Garage Equip.	-	-	51,019	-	2,442,774	(36,201)	(508,575)	1,934,199
38	395	Laboratory Equipment	-	-	499,621	-	1,307,729	(12,643)	(220,216)	1,087,513
39	396	Power Operated Equipment	-	-	241,068	-	1,209,326	(17,979)	(494,022)	715,304
40	397	Communication Equipment	-	-	(128,921)	-	2,262,795	(47,663)	(399,087)	1,863,708
41	398	Miscellaneous Equipment	-	-	7,168	-	121,811	(3,195)	(100,175)	21,636
42		Total General Plant	$ -	$ -	$ 2,822,871	$ -	$ 22,938,287	$ (1,324,058)	$ (15,413,358)	$ 7,524,929
43		Rounding					299			
44		TOTAL PLANT	$ -	$ -	$ 29,487,017	$ -	$ 380,192,497	$ (8,274,227)	$ (161,819,805)	$ 218,372,393
45		Total Plant As Per Company Books					$ 380,192,497		$ (159,524,693)	
46		RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-4, Column (C))					$ -		$ (2,295,112)	

References:
Columns (A) (B) (C) (D) (E): Company Response To RUCO Data Request 1.08
Column (F): [(Cl. (C) + Cl. (D)) X RLM-5, Pg 1, Cl. (A) X 1/2 yr. conv.] + [RLM-5, Pg 4, Cl. (E) + Cl. (D)) X RLM-5, Pg 1, Cl. (A)]
Column (G): Schedule RLM-5, Page 4, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

RATE BASE ADJUSTMENT NO. 3 - REMOVE CWIP FROM TEST-YEAR RATE BASE
TEST YEAR PLANT SCHEDULES - CONT'D
PRO FORMA ADJUSTMENTS TO TEST YEAR ENDED JUNE 30, 2006

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) ACQUISITION ADJUSTMENT PLANT ADJUSTMENTS	(B) ACQUISITION ADJUSTMENT ACC. DEP ADJUSTMENTS	(C) PLANT HELD FOR FUTURE USE	(D) CWIP	(E) RUCO ADJUSTED TOTAL PLANT VALUE	(F) RUCO ADJUSTED ACCUMULATED DEPRECIATION	(G) RUCO ADJUSTED NET PLANT VALUE
		Intangible:							
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 11,908	$ -	$ 11,908
2	303	Miscellaneous Intangible	-	-	-	-	10,522,654	(267,350)	10,255,304
3		Total Intangible Plant	$ -	$ -	$ -	$ -	$ 10,534,562	$ (267,350)	$ 10,267,212
		Other Production							
4	340	Land & Rights	$ -	$ -	$ -	$ -	$ 765,874	$ -	$ 765,874
5	341	Structures & Improvements	-	-	-	-	1,141,496	(373,643)	767,853
6	342	Fuel Holders, Producers & Acc.	-	-	-	-	1,163,837	(131,813)	1,032,024
7	343	Prime Movers	-	-	-	-	15,413,970	(2,777,622)	12,636,349
8	344	Generators	-	-	-	-	4,850,577	(266,737)	4,583,839
9	345	Accessory Electric Equipment	-	-	-	-	3,106,440	(476,780)	2,629,659
10	346	Misc. Power Plant Equipment	-	-	-	-	910,585	(78,379)	832,206
11		Total Other Production	$ -	$ -	$ -	$ -	$ 27,352,778	$ (4,104,975)	$ 23,247,804
		Transmission :							
12	350	Land & Rights	$ -	$ -	$ (320,000)	$ -	$ 957,990	$ -	$ 957,990
13	352	Structures & Improvements	-	-	-	-	191,668	(151,773)	39,895
14	353	Station Equipment	-	-	-	-	17,749,373	(6,746,715)	11,002,658
15	354	Towers & Fixtures	-	-	-	-	521,825	(136,450)	385,375
16	355	Poles & Fixtures	-	-	-	-	12,270,355	(6,739,582)	5,530,774
17	356	Overhead Conductors & Devices	-	-	-	-	11,237,573	(4,420,047)	6,817,526
18	359	Roads & Trails	-	-	-	-	183,860	(75,079)	108,782
19		Total Transmission Plant	$ -	$ -	$ (320,000)	$ -	$ 43,112,645	$ (18,269,646)	$ 24,843,000
		Distribution:							
20	360	Land & Rights	$ -	$ -	$ (120,000)	$ -	$ 1,117,885	$ -	$ 1,117,885
21	361	Structures & Improvements	-	-	-	-	4,079,498	(885,161)	3,194,336
22	362	Station Equipment	-	-	-	-	32,948,470	(15,109,599)	17,838,871
23	364	Poles, Towers & Fixtures	-	-	-	-	76,284,703	(37,427,907)	38,856,796
24	365	Overhead Conductors & Devices	-	-	-	-	49,720,736	(24,292,689)	25,428,047
25	366	Underground Conduit	-	-	-	-	12,601,063	(4,305,341)	8,295,722
26	367	UG Conductors & Devices	-	-	-	-	27,259,007	(10,229,367)	17,029,640
27	368	Line Transformers	-	-	-	-	47,499,187	(22,430,357)	25,068,830
28	369	Services	-	-	-	-	10,695,563	(4,727,199)	5,968,365
29	370	Meters	-	-	-	-	9,796,742	(3,025,580)	6,771,162
30	373	Street Lights & Signal Systems	-	-	-	-	3,811,071	(1,331,277)	2,479,794
31		Total Distribution Plant	$ -	$ -	$ (120,000)	$ -	$ 275,813,925	$ (123,764,476)	$ 152,049,449
		General:							
32	389	Land & Rights	$ -	$ -	$ -	$ -	$ 57,580	$ -	$ 57,580
33	390	Structures & Improvements	-	-	-	-	1,852,506	(837,759)	1,014,747
34	391	Office Furniture & Equipment	-	-	-	-	3,220,489	(1,209,617)	2,010,872
35	392	Transportation Equipment	-	-	-	-	10,340,406	(11,586,203)	(1,245,797)
36	393	Stores Equipment	-	-	-	-	122,871	(57,704)	65,167
37	394	Tools, Shop And Garage Equip.	-	-	-	-	2,442,774	(508,575)	1,934,199
38	395	Laboratory Equipment	-	-	-	-	1,307,729	(220,216)	1,087,513
39	396	Power Operated Equipment	-	-	-	-	1,209,326	(494,022)	715,304
40	397	Communication Equipment	-	-	-	-	2,262,795	(399,087)	1,863,708
41	398	Miscellaneous Equipment	-	-	-	-	121,811	(100,175)	21,636
42		Total General Plant	$ -	$ -	$ -	$ -	$ 22,938,287	$ (15,413,358)	$ 7,524,929
43		TOTAL PLANT	$ -	$ -	$ (440,000)	$ -	$ 379,752,198	$ (161,819,805)	$ 217,932,393
44		Total Plant As Per Company As Filed	$ -	$ -	$ (440,000)	$ 10,761,154	$ 390,513,651	$ (159,524,693)	$ -
45		Difference	$ -	$ -	$ -	$ (10,761,154)	$ (10,761,453)	$ (2,295,112)	$ 217,932,393
48		RUCO Adjustment To Remove CWIP From Rate Base (See RLM-4, Column (D))					$ (10,761,453)		

ferences: Columns (A) (B) (C): RUCO Made No Adjustments To The Company's Filing
Column (D): RUCO Adjustment To Remove CWIP From Rate Base
Column (E): Schedule RLM-5, Page 6, Column (E) + Columns (A) (B) (C) + (D)
Column (F): Schedule RLM-5, Page 6, Column (G)
Column (G): Column (E) + Column (F)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

OPERATING INCOME STATEMENT

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
	Operating Revenues:					
1	Electric Retail Revenues	$ 156,651,860	$ -	$ 156,651,860	$ 1,253,233	$ 157,905,093
2	Sales for Resale	246,016	-	246,016	-	246,016
3	Other Operating Revenue	1,589,014	48,648	1,637,662	-	1,637,662
4	TOTAL OPERATING REVENUES	$ 158,486,890	$ 48,648	$ 158,535,538	$ 1,253,233	$ 159,788,771
	Operating Expenses:					
5	Purchased Power	$ 106,224,185	$ (152)	$ 106,224,033	$ -	$ 106,224,033
6	Total O & M Expense	26,423,248	(1,718,408)	24,704,841	-	24,704,841
7	Depreciation and Amortization	11,812,574	(594,056)	11,218,518	-	11,218,518
8	Taxes Other than Income Taxes	3,447,533	(660,314)	2,787,219	-	2,787,219
9	Income Taxes	1,837,339	1,359,207	3,196,546	487,658	3,684,204
10	TOTAL OPERATING EXPENSES	$ 149,744,879	$ (1,613,723)	$ 148,131,156	$ 487,658	$ 148,618,815
11	OPERATING INCOME (LOSS)	$ 8,742,011	$ 1,662,371	$ 10,404,382	$ 765,575	$ 11,169,957

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Testimony, RLM And Schedule RLM-1
Column (E): Column (C) + Column (D)

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SERVICE FEES & LATE FEES TESTIMONY-MDC	(C) ADJ. NO. 2 PENSION & BENEFITS TESTIMONY-RLM	(D) ADJ. NO. 3 WORKER'S COMP. TESTIMONY-RLM	(E) ADJ. NO. 4 INCENTIVE COMP. TESTIMONY-RLM	(F) ADJ. NO. 5 RATE CASE EXPENSE TESTIMONY-RLM	(G) ADJ. NO. 6 BAD DEBT EXPENSE TESTIMONY-MDC	(H) ADJ. NO. 7 FLEET FUEL EXPENSE TESTIMONY-MDC	(I) ADJ. NO. 8 POSTAGE EXPENSE SCH. RLM-9	(J) ADJ. NO. 9 YEAR-END ACCURALS TESTIMONY-MDC
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ 156,651,860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	447	**Sales for Resale**	$ 246,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ 1,099,279	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	454	Rent from Electric Property	339,735	-	-	-	-	-	-	-	-	-
5	456	Other Electric Revenues	150,000	-	-	-	-	-	-	-	-	-
6		**Total Other Operating Revenue**	$ 1,589,014	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Total Operating Revenue**	$ 158,486,890	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	105,021,950	-	-	-	-	-	-	-	-	-
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	202,235	-	-	-	-	-	-	(152)	-	-
12		**Total Purchased Power**	$ 105,224,185	$ -	$ -	$ -	$ -	$ -	$ -	$ (152)	$ -	$ -
		Other Power Production										
13	546	Operation Supervision & Engineering	$ 2,264	$ -	$ -	$ -	$ -	$ -	$ -	$ (454)	$ -	$ -
14	547	Fuel	266,198	-	-	-	-	-	-	-	-	-
15	548	Generation Expenses	26,287	-	-	-	-	-	-	(72)	-	-
16	549	Miscellaneous Other Power Generation	52,481	-	-	-	-	-	-	(11)	-	-
17	551	Maintenance Supervision & Engineering	54,625	-	-	-	-	-	-	(561)	-	-
18	553	Maintenance of Generating and Electric Plant	255,461	-	-	-	-	-	-	(1,046)	-	-
19	554	Maintenance of Misc. Other Power Generation Plt	80,460	-	-	-	-	-	-	(555)	-	-
		Transmission Expense										
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	66,776	-	-	-	-	-	-	-	-	-
22	561.2	Load Dispatch - Monitor & Operation Transmission System	9,394	-	-	-	-	-	-	-	-	-
23	562	Station Expenses	75,228	-	-	-	-	-	-	(192)	-	-
24	563	Overhead Line Expenses	3,324	-	-	-	-	-	-	(28)	-	-
25	565	Transmission of Electricity by Others	7,009,879	-	-	-	-	-	-	-	-	-
26	566	Miscellaneous Transmission Expenses	19,495	-	-	-	-	-	-	(124)	-	-
27	567	Rents	11,857	-	-	-	-	-	-	-	-	-
28	568	Maintenance Supervision & Engineering	24	-	-	-	-	-	-	-	-	-
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	20,513	-	-	-	-	-	-	(454)	-	-
31	571	Maintenance of Overhead Lines	7,354	-	-	-	-	-	-	(24)	-	-
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	364,186	-	-	-	-	-	-	(500)	-	-
34	581	Load Dispatching	437,055	-	-	-	(799)	-	-	(3,218)	-	-
35	582	Station Expenses	72,715	-	-	-	-	-	-	(244)	-	-
36	583	Overhead Line Expenses	811,053	-	-	-	-	-	-	(1,971)	-	-
37	584	Underground Line Expenses	511,510	-	-	-	-	-	-	(3,868)	-	-
38	585	Street Lighting & Signal System Expenses	1,628	-	-	-	-	-	-	(10)	-	-
39	586	Meter Expenses	743,347	-	-	-	-	-	-	(5,837)	-	-
40	587	Customer Installations Expense	15,998	-	-	-	-	-	-	(102)	-	-
41	588	Miscellaneous Distribution Expenses	351,137	-	(108)	-	(9,375)	-	-	(2,577)	-	-
42	589	Rents	99,440	-	-	-	-	-	-	-	-	-
43	590	Maintenance Supervision & Engineering	54,430	-	-	-	-	-	-	(560)	-	-
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	472,734	-	-	-	-	-	-	(3,198)	-	-
46	593	Maintenance of Overhead Lines	1,006,308	-	-	-	(9,879)	-	-	(5,569)	-	-
47	594	Maintenance of Underground Lines	142,605	-	-	-	-	-	-	(1,082)	-	-
48	595	Maintenance of Line Transformers	103,998	-	-	-	-	-	-	(484)	-	-
49	596	Maintenance of Street Lighting & Signal Systems	56,424	-	-	-	-	-	-	(481)	-	-
50	597	Maintenance of Meters	123	-	-	-	-	-	-	-	-	-
51	598	Maintenance of Miscellaneous Distribution Plant	7,233	-	-	-	-	-	-	(10)	-	-

UNS Electric, Inc.
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Test Year Ended June 30, 2006

Schedule RLM-8
Pages 1 & 2 of 6

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SERVICE FEES & LATE FEES TESTIMONY-MDC	(C) ADJ. NO. 2 PENSION & BENEFITS TESTIMONY-RLM	(D) ADJ. NO. 3 WORKER'S COMP. TESTIMONY-RLM	(E) ADJ. NO. 4 INCENTIVE COMP. TESTIMONY-RLM	(F) ADJ. NO. 5 RATE CASE EXPENSE TESTIMONY-RLM	(G) ADJ. NO. 6 BAD DEBT EXPENSE TESTIMONY-MDC	(H) ADJ. NO. 7 FLEET FUEL EXPENSE TESTIMONY-MDC	(I) ADJ. NO. 8 POSTAGE EXPENSE SCH. RLM-9	(J) ADJ. NO. 9 YEAR-END ACCURALS TESTIMONY-MDC
		Customer Account Expense										
52	901	Supervision	172,327	-	(26)	-	(14,699)	-	-	(1,453)	-	-
53	902	Meter Reading Expenses	730,556	-	-	-	-	-	-	(774)	-	-
54	903	Customer Records & Collection Expenses	3,834,499	-	(209)	-	(1,600)	-	-	(7,905)	(37,956)	-
55	904	Uncollectible Accounts	579,538	-	-	-	-	-	(203,038)	-	-	-
56	905	Miscellaneous Customer Accounts Expenses	29,171	-	-	-	-	-	-	(117)	-	-
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	34,001	-	-	-	-	-	-	(460)	-	-
59	909	Informational and Instructional Advertising Expenses	62,059	-	-	-	(5,850)	-	-	(439)	-	-
60	910	Miscellaneous Customer Service & Informational Expenses	9,778	-	-	-	-	-	-	(11)	-	-
		Administrative and General Expense										
61	920	Administrative & General Salaries	770,768	-	-	-	(56,045)	-	-	-	-	-
62	921	Office Supplies & Expenses	535,854	-	(10,129)	-	-	-	-	(6,625)	-	-
63	922	Administrative Expenses Transferred - Credit	(158,087)	-	-	-	-	-	-	-	-	-
64	923	Outside Services Employed	3,317,593	-	-	-	-	-	-	-	-	-
65	924	Property Insurance	65,598	-	-	-	-	-	-	-	-	-
66	925	Injuries and Damages	512,417	-	-	(63,252)	-	-	-	(10)	-	-
67	926	Employee Pension & Benefits	1,172,133	-	-	-	-	-	-	-	-	(6,256)
68	928	Regulatory Commission Expenses	200,000	-	-	-	-	(116,333)	-	-	-	-
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	82,478	-	(1,139)	-	-	-	-	-	-	-
71	930.2	Miscellaneous General Expenses	1,148,557	-	-	-	-	-	-	(2,071)	-	-
72	931	Rents	74,558	-	-	-	-	-	-	-	-	-
73	935	Maintenance of General Plant	35,937	-	-	-	-	-	-	-	-	-
74		**Total Operation and Maintenance Expense**	$ 26,423,248	$ -	$ (11,612)	$ (63,252)	$ (98,247)	$ (116,333)	$ (203,038)	$ (53,098)	$ (37,956)	$ (6,256)
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ 998,011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	403/404/406	Other Production Plant	182,444	-	-	-	-	-	-	-	-	-
77	403/404/406	Transmission Plant	1,203,457	-	-	-	-	-	-	-	-	-
78	403/404/406	Distribution Plant	9,059,006	-	-	-	-	-	-	-	-	-
79	403/404/406	General Plant	369,656	-	-	-	-	-	-	-	-	-
80		**Total Depreciation & Amortization - All**	$ 11,812,574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ 192,787	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	408	Property Tax - Transmission	327,975	-	-	-	-	-	-	-	-	-
83	408	Property Tax - Distribution	2,284,584	-	-	-	-	-	-	-	-	-
84	408	Property Tax - General	291,025	-	-	-	-	-	-	-	-	-
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	348,088	-	-	-	(8,320)	-	-	-	-	-
86	408	Medical and Dental	2,773	-	-	-	-	-	-	-	-	-
87	408	Other	301	-	-	-	-	-	-	-	-	-
88		**Total Taxes Other Than Income Taxes**	$ 3,447,533	$ -	$ -	$ -	$ (8,320)	$ -	$ -	$ -	$ -	$ -
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ 1,342,818	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	410	Deferred IT - Federal & State (debit)	10,602,572			-	-	-	-	-	-	-
91	411	Deferred IT - Federal & State (credit)	(10,108,051)	-	-	-	-	-	-	-	-	-
92		**Total Income Taxes**	$ 1,837,339	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93		**Total Operating Expense**	$ 149,744,879	$ -	$ (11,612)	$ (63,252)	$ (106,567)	$ (116,333)	$ (203,038)	$ (53,250)	$ (37,956)	$ (6,256)
94		OPERATING INCOME	$ 8,742,011									

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 A & G EXPENSE CAPITALIZED TESTIMONY-MDC	(L) ADJ. NO. 11 DEP/PROP TX FOR CWIP TESTIMONY-MDC	(M) ADJ. NO. 12 CORP. COSTS ALLOCATIONS TESTIMONY-MDC	(N) ADJ. NO. 13 DEP/AMORT ANNUALIZ'N SCH. RLM-10	(O) ADJ. NO. 14 VALENCIA TURBINE FUEL TESTIMONY-MDC	(P) ADJ. NO. 15 PROPERTY TAX SCH. RLM-11	(Q) ADJ. NO. 16 SERP TESTIMONY-RLM	(R) ADJ. NO. 17 INAPPROPRIATE EXPENSES SCH. RLM-12	(S) ADJ. NO. 18 O/H LINES MAINTENANCE SCH. RLM-13	(T) ADJ. NO. 19 CUST. SERVICE COST ALLOC. SCH. RLM-14
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	447	**Sales for Resale**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	-
5	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	-
6		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	-	-	-	-	-	-	-	-	-	-
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	-	-	-	-	-	-	-	-	-	-
12		**Total Purchased Power**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Power Production										
13	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	547	Fuel	-	-	-	-	(265,198)	-	-	-	-	-
15	548	Generation Expenses	-	-	-	-	-	-	-	-	-	-
16	549	Miscellaneous Other Power Generation	-	-	-	-	-	-	-	-	-	-
17	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
18	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	-
19	554	Maintenance of Misc. Other Power Generation Plt	-	-	-	-	-	-	-	-	-	-
		Transmission Expense										
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	-	-	-	-	-	-	-	-	-	-
22	561.2	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	-
23	562	Station Expenses	-	-	-	-	-	-	-	-	-	-
24	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
25	565	Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	-
26	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	-
27	567	Rents	-	-	-	-	-	-	-	-	-	-
28	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
31	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	-
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
34	581	Load Dispatching	-	-	-	-	-	-	-	-	-	-
35	582	Station Expenses	-	-	-	-	-	-	-	-	-	-
36	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
37	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	-
38	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	-
39	586	Meter Expenses	-	-	-	-	-	-	-	-	-	-
40	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	-
41	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	-	-
42	589	Rents	(54)	-	-	-	-	-	-	-	-	-
43	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
46	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	(257,678)	-
47	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	-
48	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	-
49	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	-
50	597	Maintenance of Meters	-	-	-	-	-	-	-	-	-	-
51	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	-

UNS Electric, Inc.
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Test Year Ended June 30, 2006

SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 A & G EXPENSE CAPITALIZED TESTIMONY-MDC	(L) ADJ. NO. 11 DEP/PROP TX FOR CWIP TESTIMONY-MDC	(M) ADJ. NO. 12 CORP. COSTS ALLOCATIONS TESTIMONY-MDC	(N) ADJ. NO. 13 DEP/AMORT ANNUALIZ'N SCH. RLM-10	(O) ADJ. NO. 14 VALENCIA TURBINE FUEL TESTIMONY-MDC	(P) ADJ. NO. 15 PROPERTY TAX SCH. RLM-11	(Q) ADJ. NO. 16 SERP TESTIMONY-RLM	(R) ADJ. NO. 17 INAPPROPRIATE EXPENSES SCH. RLM-12	(S) ADJ. NO. 18 O/H LINES MAINTENANCE SCH. RLM-13	(T) ADJ. NO. 19 CUST. SERVICE COST ALLOC. SCH. RLM-14
		Customer Account Expense										
52	901	Supervision	-	-	-	-	-	-	-	-	-	-
53	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	-
54	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	(45,230)
55	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
56	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	-
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-	-
59	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	-
60	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	-
		Administrative and General Expense										
61	920	Administrative & General Salaries	-	-	-	-	-	-	-	-	-	(2,346)
62	921	Office Supplies & Expenses	(128)	-	-	-	-	-	-	(21,320)	-	(1,029)
63	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(12)
64	923	Outside Services Employed	(301,005)	-	-	-	-	-	-	(20,311)	-	(236)
65	924	Property Insurance	-	-	-	-	-	-	-	-	-	(123)
66	925	Injuries and Damages	-	-	-	-	-	-	-	-	-	(27)
67	926	Employee Pension & Benefits	-	-	-	-	-	-	(83,506)	-	-	(13,242)
68	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	-
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	-	-	-	-	-	-	-	(3,539)	-	-
71	930.2	Miscellaneous General Expenses	-	-	(10,010)	-	-	-	-	(28,451)	-	-
72	931	Rents	-	-	-	-	-	-	-	-	-	-
73	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	-
74		**Total Operation and Maintenance Expense**	$ (301,187)	$ -	$ (10,010)	$ -	$ (266,198)	$ -	$ (83,506)	$ (73,620)	$ (267,678)	$ (62,245)
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ -	$ (11,923)	$ -	$ (7,822)	$ -	$ -	$ -	$ -	$ -	$ -
76	403/404/406	Other Production Plant	-	(8,839)	-	(9,640)	-	-	-	-	-	-
77	403/404/406	Transmission Plant	-	(48,905)	-	5,995	-	-	-	-	-	-
78	403/404/406	Distribution Plant	-	(363,618)	-	40,227	-	-	-	-	-	-
79	403/404/406	General Plant	-	(16,731)	-	(170,844)	-	-	-	-	-	(2,156)
80		**Total Depreciation & Amortization - All**	$ -	$ (449,816)	$ -	$ (142,085)	$ -	$ -	$ -	$ -	$ -	$ (2,156)
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ -	$ (9,134)	$ -	$ -	$ -	$ (26,392)	$ -	$ -	$ -	$ -
82	408	Property Tax - Transmission	-	(31,707)	-	-	-	(43,718)	-	-	-	-
83	408	Property Tax - Distribution	-	(191,846)	-	-	-	(301,058)	-	-	-	-
84	408	Property Tax - General	-	(18,009)	-	-	-	(38,733)	-	-	-	-
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-	-	-
86	408	Medical and Dental	-	-	-	-	-	-	-	-	-	-
87	408	Other	-	-	-	-	-	-	-	-	-	(2,397)
88		**Total Taxes Other Than Income Taxes**	$ -	$ (239,696)	$ -	$ -	$ -	$ (409,902)	$ -	$ -	$ -	$ (2,397)
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	410	Deferred IT - Federal & State (debit)	-	-	-	-	-	-	-	-	-	-
91	411	Deferred IT - Federal & State (credit)	-	-	-	-	-	-	-	-	-	-
92		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93		**Total Operating Expense**	$ (301,187)	$ (689,512)	$ (10,010)	$ (142,085)	$ (266,198)	$ (409,902)	$ (83,506)	$ (73,620)	$ (267,678)	$ (66,797)
94		OPERATING INCOME										

UNS Electric, Inc.
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SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(U) ADJ. NO. 20 ATYPICAL EXPENSES TESTIMONY-RLM	(V) ADJ. NO. 21 OUTSIDE SERVICES - DSM TESTIMONY-MDC	(W) INTENTIONALLY LEFT BLANK	(X) INTENTIONALLY LEFT BLANK	(Y) INTENTIONALLY LEFT BLANK	(Z) INTENTIONALLY LEFT BLANK	(AA) INTENTIONALLY LEFT BLANK	(AB) INTENTIONALLY LEFT BLANK	(AC) ADJ. NO. 22 INCOME TAX SCH. RLM-15	(AD) RUCO AS ADJUSTED
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,651,860
2	447	**Sales for Resale**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 246,016
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,147,927
4	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	339,735
5	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	150,000
6		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,637,662
7		**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,535,538
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	-	-	-	-	-	-	-	-	-	106,021,950
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	-	-	-	-	-	-	-	-	-	202,083
12		**Total Purchased Power**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 106,224,033
		Other Power Production										
13	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,810
14	547	Fuel	-	-	-	-	-	-	-	-	-	-
15	548	Generation Expenses	-	-	-	-	-	-	-	-	-	26,215
16	549	Miscellaneous Other Power Generation	-	-	-	-	-	-	-	-	-	52,470
17	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	54,064
18	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	254,415
19	554	Maintenance of Misc. Other Power Generation Plt	-	-	-	-	-	-	-	-	-	79,905
		Transmission Expense										-
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	-	-	-	-	-	-	-	-	-	66,776
22	561.2	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	9,394
23	562	Station Expenses	-	-	-	-	-	-	-	-	-	75,036
24	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	3,296
25	565	Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	7,009,878
26	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	19,371
27	567	Rents	-	-	-	-	-	-	-	-	-	11,857
28	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	24
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	20,059
31	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	7,330
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	363,686
34	581	Load Dispatching	-	-	-	-	-	-	-	-	-	433,038
35	582	Station Expenses	-	-	-	-	-	-	-	-	-	72,471
36	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	809,082
37	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	507,642
38	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	1,618
39	586	Meter Expenses	-	-	-	-	-	-	-	-	-	737,510
40	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	15,896
41	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	-	339,077
42	589	Rents	-	-	-	-	-	-	-	-	-	99,386
43	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	53,870
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	469,536
46	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	723,181
47	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	141,523
48	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	103,484
49	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	55,943
50	597	Maintenance of Meters	-	-	-	-	-	-	-	-	-	123
51	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	7,223

UNS Electric, Inc.
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SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(U) ADJ. NO. 20 ATYPICAL EXPENSES TESTIMONY-RLM	(V) ADJ. NO. 21 OUTSIDE SERVICES - DSM TESTIMONY-MDC	(W) INTENTIONALLY LEFT BLANK	(X) INTENTIONALLY LEFT BLANK	(Y) INTENTIONALLY LEFT BLANK	(Z) INTENTIONALLY LEFT BLANK	(AA) INTENTIONALLY LEFT BLANK	(AB) INTENTIONALLY LEFT BLANK	(AC) ADJ. NO. 22 INCOME TAX SCH. RLM-15	(AD) RUCO AS ADJUSTED
		Customer Account Expense										
52	901	Supervision	-	-	-	-	-	-	-	-	-	156,148
53	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	729,782
54	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	3,741,599
55	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	376,500
56	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	29,054
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	-	(49,920)	-	-	-	-	-	-	-	(16,379)
59	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	55,770
60	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	9,767
		Administrative and General Expense										
61	920	Administrative & General Salaries	-	-	-	-	-	-	-	-	-	712,377
62	921	Office Supplies & Expenses	(1,382)	-	-	-	-	-	-	-	-	495,240
63	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(158,099)
64	923	Outside Services Employed	(12,869)	-	-	-	-	-	-	-	-	2,983,173
65	924	Property Insurance	-	-	-	-	-	-	-	-	-	65,475
66	925	Injuries and Damages	-	-	-	-	-	-	-	-	-	449,128
67	926	Employee Pension & Benefits	-	-	-	-	-	-	-	-	-	1,069,129
68	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	83,667
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	-	-	-	-	-	-	-	-	-	77,800
71	930.2	Miscellaneous General Expenses	-	-	-	-	-	-	-	-	-	1,108,025
72	931	Rents	-	-	-	-	-	-	-	-	-	74,558
73	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	35,937
74		**Total Operation and Maintenance Expense**	$ (14,251)	$ (49,920)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,704,841
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 978,366
76	403/404/406	Other Production Plant	-	-	-	-	-	-	-	-	-	163,965
77	403/404/406	Transmission Plant	-	-	-	-	-	-	-	-	-	1,160,647
78	403/404/406	Distribution Plant	-	-	-	-	-	-	-	-	-	8,735,615
79	403/404/406	General Plant	-	-	-	-	-	-	-	-	-	179,925
80		**Total Depreciation & Amortization - All**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,218,518
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,261
82	408	Property Tax - Transmission	-	-	-	-	-	-	-	-	-	252,550
83	408	Property Tax - Distribution	-	-	-	-	-	-	-	-	-	1,801,680
84	408	Property Tax - General	-	-	-	-	-	-	-	-	-	234,283
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-	-	339,768
86	408	Medical and Dental	-	-	-	-	-	-	-	-	-	2,773
87	408	Other	-	-	-	-	-	-	-	-	-	(2,096)
88		**Total Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,787,219
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,359,207	$ 2,702,025
90	410	Deferred IT - Federal & State (debit)	-	-	-	-	-	-	-	-	-	10,602,572
91	411	Deferred IT - Federal & State (credit)	-	-	-	-	-	-	-	-	-	(10,108,051)
92		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,359,207	$ 3,196,546
93	**Total Operating Expense**		$ (14,251)	$ (49,920)	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,359,207	$ 148,131,156
94	OPERATING INCOME											$ 10,404,382

UNS Electric, Inc.
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Test Year Ended June 30, 2006

OPERATING INCOME ADJUSTMENT NO. 8
NORMALIZATION OF POSTAGE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE		(A) POSTAGE
	Calculation To Annualize Postage Costs To Recognize January 2006 Postal Increase			
1	Actual Test-Year Postal Costs	Company Workpapers	$	275,038
2	Actual Postal Costs January Thru June (Including Postal Increase)	Company Workpapers		146,957
3	RUCO Estimate Of Postage Costs Prior January Postal Increase	Line 1 - Line 2	$	128,081
4	January 8, 2006 Postage Increase			5.00%
5	Annualized Postage Cost For January Postal Increase	Line 3 + 5.00% Increase	$	134,485
6	RUCO Total Annualized Test-Year Postage Cost	Line 2 + Line 5	$	281,442
	Calculation To Normalize Postage Costs To Recognize May 2007 Postal Increase			
7	May 14, 2007 Postage Increase			5.13%
8	RUCO Adjusted Postage Cost To Recognize January 2006 Increase	Line 6 + 5.13% Increase		295,875
	Calculation To Annualize Postage Costs To Recognize Annualized Customer Base			
9	RUCO Adjusted Postage Cost To Recognize January 2006 Increase	Line 8	$	295,875
10	Actual Number Of Test-Year Customer Bills	Company Schedule H-2		89,596
11	Cost Per Customer Bill	Line 9 / Line 10	$	3.3023
12	RUCO Annualized Number Of Test-Year Customer Bills	Company Workpapers		91,864
13	RUCO Adjusted Postage Costs For Annualized Customer Base	Line 11 X Line 12	$	303,365
14	Company As Filed	Company Workpapers		341,321
15	Difference	Line 13 - Line 14	$	(37,956)
16	RUCO Adjustment (See RLM-8, Pages 1 & 2, Column (I))	Line 15	$	(37,956)

UNS Electric, Inc.
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Test Year Ended June 30, 2006

OPERATING INCOME ADJUSTMENT NO. 13
TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE

LINE NO.	ACCT. NO.	DESCRIPTION	(A) RUCO TOTAL PLANT AS ADJUSTED	(B) COMPANY PROP'D DEP. RATE	(C) RUCO DEPREC'N EXPENSE	(D) CO. COMPUTED NET OF CWIP DEP. EXP.	(E) DIFFERENCE
		Intangible:					
1	302	Franchises & Consents	$ 11,908	4.00%	$ 476		
2	303	Miscellaneous Intangible	10,522,654	6.59%	693,592		
3		Total Intangible Plant	$ 10,534,562		$ 694,069	$ 701,891	$ (7,822)
		Other Production					
	340	Land & Rights	$ 765,874	0.00%	$ -		
7	341	Structures & Improvements	1,141,496	2.07%	23,629		
8	342	Fuel Holders, Producers & Acc.	1,163,837	2.51%	29,212		
9	343	Prime Movers	15,413,970	2.53%	389,973		
10	344	Generators	4,850,577	2.33%	113,018		
11	345	Accessory Electric Equipment	3,106,440	2.35%	73,001		
12	346	Misc. Power Plant Equipment	910,585	2.64%	24,039		
13		Total Other Production	$ 27,352,778		$ 652,874	$ 662,514	$ (9,640)
14		Transmission :					
	350	Land & Rights	$ 957,990	0.55%	$ 5,239		
15	352	Structures & Improvements	191,668	3.13%	5,999		
	353	Station Equipment	17,749,373	3.15%	559,105		
16	354	Towers & Fixtures	521,825	5.03%	26,248		
17	355	Poles & Fixtures	12,270,355	4.48%	549,712		
18	356	Overhead Conductors & Devices	11,237,573	2.66%	298,919		
19	359	Roads & Trails	183,860	2.02%	3,714		
20		Total Transmission Plant	$ 43,112,645		$ 1,448,937	$ 1,442,942	$ 5,995
21		Distribution:			-		
22	360	Land & Rights	$ 1,117,885	0.15%	$ 1,654		
23	361	Structures & Improvements	4,079,498	2.96%	120,753		
24	362	Station Equipment	32,948,470	4.09%	1,347,592		
25	364	Poles, Towers & Fixtures	76,284,703	4.14%	3,158,187		
26	365	Overhead Conductors & Devices	49,720,736	4.13%	2,053,466		
27	366	Underground Conduit	12,601,063	3.79%	477,580		
28	367	UG Conductors & Devices	27,259,007	4.40%	1,199,396		
29	368	Line Transformers	47,499,187	4.63%	2,199,212		
30	369	Services	10,695,563	3.76%	402,553		
	370	Meters	9,796,742	3.11%	304,679		
31	373	Street Lights & Signal Systems	3,811,071	4.04%	153,967		
		Total Distribution Plant	$275,813,925		$ 11,419,040	$ 11,378,813	$ 40,227
32		General:					
33	389	Land & Rights	$ 57,580	0.00%	$ -		
34	390	Structures & Improvements	1,852,506	2.65%	49,091		
35	391	Office Furniture & Equipment	3,220,489	9.11%	293,529		
36	392	Transportation Equipment	10,340,406	13.20%	1,365,407		
37	393	Stores Equipment	122,871	3.03%	3,723		
38	394	Tools, Shop And Garage Equip.	2,442,774	3.45%	84,276		
39	395	Laboratory Equipment	1,307,729	2.50%	32,693		
40	396	Power Operated Equipment	1,209,326	6.92%	83,685		
41	397	Communication Equipment	2,262,795	4.35%	98,432		
42	398	Miscellaneous Equipment	121,811	5.56%	6,773		
43		Total General Plant	$ 22,938,287		$ 2,017,609	$ 2,188,453	$ (170,844)
		SUB TOTALS			$ 16,232,528	$ 16,374,613	$ (142,085)
44		Annualized Amortization - Acquisition Discount			(3,781,656)	(3,781,656)	
45		Vehicle Depreciation Charged To CWIP			(897,691)	(897,691)	
46		Adjustment Difference - Booked Value To Company Computation			117,308	117,308	
47		TOTALS	$379,752,198		$ 11,670,489	$ 11,812,574	$ (142,085)
48		Company Test-Year Depreciation As Filed			$ 11,812,574		
49		Difference			$ (142,085)		
50		RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (N))			$ (142,085)		

UNS Electric, Inc.
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OPERATING INCOME ADJUSTMENT NO. 15
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service (RLM-4, Column (H), Line 7)		$ 135,883,118
2	Licensed Transportation (Company Workpapers)	$ (3,834,788)	
3	Land Cost And Rights (Company Workpapers)	(1,816,844)	
4	Environmental Property (Company Workpapers)	(5,563,286)	
5	Non-Taxable WAPA Portion Of N Havasu Sub	(4,674,822)	
6	CWIP In Rate Base	(10,802,316)	
7	Net Book Value Of Generation	(17,285,854)	
8	Full Cash Value Of Generation	7,943,440	
9	Land FCV Per ADOR (Company Workpapers)	1,551,539	
10	Material And Supplies (Company Workpapers)	5,650,559	
11	COMPANY'S FULL CASH VALUE (Sum Of Lines 1 Thru 10)		$ 107,050,746
	Calculation Of The Company's Tax Liability:		
8	Assessment Ratio (Per House Bill 2779)	23.0%	
9	Assessed Value (Line 7 X Line 8)	$ 24,621,672	
10	Average Tax Rate (Company Workpapers)	9.69%	
13	PROPERTY TAX Excluding Environmental Property (Line 9 X Line 10)		$ 2,384,806
14	Environmental Property (Line 4)	$ 5,563,286	
15	Statutory FCV Adjustment (Company Workpapers)	50%	
16	Environmental Property FVC (Line14 X Line 15)	$ 2,781,643	
17	Asessment Ratio Line 8)	23.0%	
18	Taxable Value (Line 16 X Line 17)	$ 639,778	
19	Average Tax Rate (Company Workpapers)	9.69%	
20	PROPERTY TAX On Environmental Property (Line 18 X Line 19)		$ 61,968
21	PROPERTY TAX On Leased Property (Company Workpapers)		
22	COMPANY PROPERTY TAX LIABILITY (Sum Of Lines 13, 20 & 21)		$ 2,446,773
23	Total Test Year Adjusted Property Tax Expense Per Company's Filing	$ 3,096,371	
24	Property Tax Associated With CWIP	(239,696)	
25	Rounding	(8)	
26	Net Test Year Adjusted Property Tax Expense Per Company's Filing	$ 2,856,667	
27	Decrease In Property Tax Expense (Line 22 - Line 26)	$ (409,893)	

	Distribution Of Property Tax Adjustment	COMPANY WORKPAPERS	ALLOCATION FACTOR	RUCO ALLOCATION
28	Generation	$ 184,653	6.44%	$ (26,392)
29	Transmission	305,868	10.67%	(43,718)
30	Distribution	2,106,338	73.45%	(301,058)
31	General/Intangible	270,993	9.45%	(38,733)
32	Totals	$ 2,867,852	100.00%	$ (409,902)

33	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (Line 24) (See RLM-8, Pages 3 & 4, Column (P))	$ (409,902)

UNS Electric, Inc.
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OPERATING INCOME ADJUSTMENT NO. 17
RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT
	Expenses Removed		
1	Account 921 - A & G Expense - Office Supplies:	RUCO Workpapers - Exhibit B 0921	(21,320)
2	Account 923 - A & G Expense - Outside Services Employed:	RUCO Workpapers - Exhibit B 0923	(20,311)
3	Account 930 - A & G Expense - Miscellaneous General Expenses:	RUCO Workpapers - Exhibit B 0930	(28,451)
4	Total Expenses Removed	Sum Of Lines 1 Thru 6	$ (70,081)
5	RUCO Adjustment (See RLM-8, Pages 3 & 4, Column (R) For Distribution)	Line 7	$ (70,081)

UNS Electric Corporation
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Test Year Ended June 30, 2006

EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
AUG-05	0921	Projects	PVS Net - Procard Charges		906 FASTRIP FOOD S	47.33		47.33	Inappropriate - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		A FRAME OF MIND	38.83		38.83	Inappropriate - Employee Plaque
AUG-05	0921	Projects	PVS Net - Procard Charges		AIRTRANAI 33212712643762	228.39		228.39	Out-Of-State Expense ?
JUL-05	0921	Projects	PVS Net - Procard Charges		ALADDIN-ZANZIBAR CAFE	29.75		29.75	Out-Of-State Expense?
OCT-05	0921	Projects	PVS Net - Procard Charges		ALBERTSONS #967 S9H	23.45		23.45	Inappropriate - Emplloyee Meeting
MAR-06	0921	Projects	PVS Net - Procard Charges		AZ REPUBLIC SUBSCRIPTI	200.20		200.20	Newspaper Subscription
FEB-06	0921	Projects	PVS Net - Procard Charges		AZ TOWN HALL	50.00		50.00	**Sponsorship - UNSE Agrees To Remove**
OCT-05	0921	Projects	PVS Net - Procard Charges		BARLEY BROTHERS BREWER	40.13		40.13	Inappropriate - Business Meal
MAR-06	0921	Projects	PVS Net - Procard Charges		BARNES & NOBLE #2962	27.02		27.02	Office Supplies ?
JUN-06	0921	Projects	PVS Net - Procard Charges		BASHA S 30 SYW	10.28		10.28	Inappropriate - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		BASHAS #116 SYW	5.97		5.97	Inappropriate - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		BASHAS #116 SYW	22.67		22.67	Inappropriate - Emplloyee Meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		BEER BOTTOM'S BISTRO	42.75		42.75	Inappropriate - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		BRUEGGERS BAGEL BAKERY	7.62		7.62	Inappropriate - Business Meal
FEB-06	0921	Projects	PVS Net - Procard Charges		BRUEGGER'S BAGELS -Q51	2.79		2.79	Inappropriate - Training Meeting
FEB-06	0921	Projects	PVS Net - Procard Charges		CARLTON CARDS #0408	47.97		47.97	Office Supplies ?
SEP-05	0921	Projects	PVS Net - Procard Charges		CHA-BONES	70.40		70.40	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	100.92		100.92	Excessive - Business Meal
JUL-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	60.11		60.11	Excessive - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	50.25		50.25	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI04600010462	70.83		70.83	Excessive - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		CHILI'S GRI41600004168	50.33		50.33	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		CHINA BUFFET - LH	56.86		56.86	Excessive - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		CHUYS MESQUITE BROILER	75.34		75.34	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 01773	5.00		5.00	Inappropriate - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05540	11.93		11.93	Inappropriate - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		CIRCLE K 05923	2.98		2.98	Inappropriate - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		COFFEE BEAN & TEA LEAF	5.37		5.37	Inappropriate - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		COLORADO BELLE F/B	10.76		10.76	Out-Of-State Expense?
DEC-05	0921	Projects	PVS Net - Procard Charges		CRACKER BARREL #416	51.73		51.73	Excessive - Business Meal
JUL-05	0921	Projects	PVS Net - Procard Charges		CRACKER BARREL #416	111.39		111.39	Excessive - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	153.59		153.59	Inappropriate - Employee Meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	50.00		50.00	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	121.69		121.69	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	108.79		108.79	Excessive - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		DAMBAR & STEAKHOUSE	56.97		56.97	Excessive - Business Meal
AUG-05	0921	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LLC	1,855.62		927.81	2-Year Amortization
OCT-05	0921	Projects	PVS Net - Procard Charges		DANONE WATERS OF NORTH	89.50		89.50	Inappropriate - Drinking Water
OCT-05	0921	Projects	PVS Net - Procard Charges		DIAMOND 1624 SHAMROCK	5.55		5.55	Inappropriate - Employee Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT	114.69		114.69	Inappropriate - Employee Meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT	30.15		30.15	Inappropriate - Employee Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		DONUT DEPOT	15.97		15.97	Inappropriate - Safety Meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		ENOTECA PIZZARIA WINE	63.91		63.91	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	37.00		37.00	Out-Of-State Expense?
JUL-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	37.00		37.00	Out-Of-State Expense?
JUN-06	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	45.00		45.00	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	27.00		27.00	Out-Of-State Expense?
OCT-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	29.00		29.00	Out-Of-State Expense?
SEP-05	0921	Projects	PVS Net - Procard Charges		FIVE STAR VALET	33.00		33.00	Out-Of-State Expense?
JAN-06	0921	Projects	PVS Net - Procard Charges		FOOD CITY #108 STP	14.97		14.97	Inappropriate - Training Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO	60.00		60.00	Inappropriate - Flowers
JAN-06	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO	98.28		98.28	Inappropriate - Flowers
SEP-05	0921	Projects	PVS Net - Procard Charges		FTD*MANDARIN ORCHID HO	60.00		60.00	Inappropriate - Flowers
NOV-05	0921	Projects	PVS Net - Procard Charges		GAYLORD TEXAN F&B	16.02		16.02	Out-Of-State Expense?
MAY-06	0921	Projects	PVS Net - Procard Charges		GOLDEN CORRAL 2465	53.19		53.19	Excessive - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		GOLD'S GYM	40.00		40.00	**Inappropriate - UNSE Agrees To Remove**
OCT-05	0921	Projects	PVS Net - Procard Charges		GREAT LAK 84612472893255	101.50		101.50	Questionable Expense?

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
FEB-06	0921	Projects	PVS Net - Procard Charges		GREAT LAK 84615481193795	127.99		127.99	Questionable Expense?
FEB-06	0921	Projects	PVS Net - Procard Charges		H.L.A FRONT DESK #1	85.89		85.89	Questionable Expense?
AUG-05	0921	Projects	PVS Net - Procard Charges		HILTON SEDONA RESORTIP	437.42		437.42	Questionable Expense ?
JUN-06	0921	Projects	PVS Net - Procard Charges		HMS HOST-LAS-AIRPT#241	3.01		3.01	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		HMS HOST-LAS-AIRPT#241	1.93		1.93	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		HMSHOST-LAS-AIRPT #008	10.75		10.75	Out-Of-State Expense?
JUL-05	0921	Projects	PVS Net - Procard Charges		HMSHOST-LAS-AIRPT #033	1.92		1.92	Out-Of-State Expense?
JUL-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416	137.76		137.76	Inappropriate - Employee Appreciation
OCT-05	0921	Projects	PVS Net - Procard Charges		HOME DEPOT #0416	200.00		200.00	Inappropriate - Employee Appreciation
OCT-05	0921	Payables		Purchase Invoices USD	HUALAPAI TRIBE	250.00		250.00	**Inappropriate - UNSE Agrees To Remove**
JUL-05	0921	Projects	PVS Net - Procard Charges		IVARS 25 SEATAC AIRPOR	19.51		19.51	Out-Of-State Expense?
MAR-06	0921	Projects	PVS Net - Procard Charges		JA STEAKHOUSE	80.60		80.60	Excessive - Business Meal
JAN-06	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL	112.80		112.80	Inappropriate - Team Meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL	51.13		51.13	Excessive - Business Meal
MAR-06	0921	Projects	PVS Net - Procard Charges		JACKSONS GRILL	210.60		210.60	Excessive - Business Meal
MAR-06	0921	Projects	PVS Net - Procard Charges		JAVELINA CANTINA	55.83		55.83	Excessive - Business Meal
JAN-06	0921	Projects	PVS Net - Procard Charges		KINGMAN CHAMBER OF COM	357.50		357.50	Dues
MAR-06	0921	Projects	PVS Net - Procard Charges		KINGMAN CHAMBER OF COM	30.00		30.00	Dues
DEC-05	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE	222.22		222.22	Excessive - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE	71.72		71.72	Excessive - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		KINGMAN DELI, THE	55.73		55.73	Excessive - Business Meal
FEB-06	0921	Payables		Purchase Invoices USD	KINGMAN MOHAVE LIONS CLUB	60.00		60.00	Dues
AUG-05	0921	Payables		Purchase Invoices USD	KINGMAN ROTARY CLUB	125.00		125.00	Dues
JAN-06	0921	Payables		Purchase Invoices USD	KINGMAN ROTARY CLUB	133.00		133.00	Dues
FEB-06	0921	Payables		Purchase Invoices USD	KINGMAN ROUTE 66 ROTARY CLUB	250.00		250.00	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		KINGMAN-CHILI'00010462	75.63		75.63	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		KMART 00095281	10.76		10.76	Office Supplies ?
MAY-06	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU CHAMBER OF	15.00		15.00	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		LAKE HAVASU-CH00010496	41.79		41.79	Dues
SEP-05	0921	Projects	PVS Net - Procard Charges		LK HAVASU CITY CHMBR	35.00		35.00	Dues
NOV-05	0921	Projects	PVS Net - Procard Charges		LOVE AND WAR IN TEXAS	49.52		49.52	Out-Of-State Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		MACARONI GR30100003012	94.49		94.49	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		MAD DOGS BAR & GRILL	27.28		27.28	Inappropriate - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO	12.00		12.00	Out-Of-State Expense?
DEC-05	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO	84.00		84.00	Out-Of-State Expense?
FEB-06	0921	Projects	PVS Net - Procard Charges		MCCARRAN INT L AVIATIO	12.00		12.00	Out-Of-State Expense?
JUN-06	0921	Payables		Purchase Invoices USD	MINKUS ADVERTISING SPECIALTIES	2,357.86		2,357.86	**Inappropriate - UNSE Agrees To Remove**
FEB-06	0921	Projects	PVS Net - Procard Charges		MOHAVE COMMUNITY C	35.00		35.00	Dues
JUL-05	0921	Projects	PVS Net - Procard Charges		MR. C'S RESTAURANT	193.49		193.49	Inappropriate - HR Related
MAR-06	0921	Projects	PVS Net - Procard Charges		MUDSHARK BREWING CO	27.23		27.23	Inappropriate - Business Meal
MAY-06	0921	Projects	PVS Net - Procard Charges		MUDSHARK BREWING CO	52.28		52.28	Inappropriate - Business Meal
JUL-05	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE	173.54		173.54	Excessive - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		NASHVILLE GRILLE	23.86		23.86	Out-Of-State Expense?
AUG-05	0921	Payables		Purchase Invoices USD	NOGALES INTERNATIONAL NEWSPAPER	49.00		49.00	Newspaper Subscription
SEP-05	0921	Projects	PVS Net - Procard Charges		NORZAGARAY FOOD MARKET	166.79		166.79	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		OMNI HOTELS TUCSON RES	350.16		350.16	Excessive Choice Of Hotel
JUN-06	0921	Projects	PVS Net - Procard Charges		ORB*M57ZGF	901.20		901.20	**Inappropriate - UNSE Agrees To Remove**
SEP-05	0921	Projects	PVS Net - Procard Charges		OUTBACK #0315	76.73		76.73	Excessive - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		P.F. CHANG'S #8000	104.09		104.09	Inappropriate - Employee Meeting
DEC-05	0921	Projects	PVS Net - Procard Charges		PALO DURO CREEK GOLF C	7.68		7.68	Out-Of-State Expense?
NOV-05	0921	Payables		Purchase Invoices USD	PERFECTION ENTERTAINMENT	350.00		350.00	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0921	Projects	PVS Net - Procard Charges		PLN*NO REFUNDS	452.01		452.01	Questionable Expense ?
NOV-05	0921	Projects	PVS Net - Procard Charges		PLN*NO REFUNDS	894.50		894.50	Questionable Expense?
AUG-05	0921	Projects	PVS Net - Procard Charges		PRESCOTT CONVENTION CT	95.96		95.96	Questionable Expense - UES Mentoring?
JUL-05	0921	Projects	PVS Net - Procard Charges		QUIK MART #33	30.67		30.67	Inappropriate - Business Meal
NOV-05	0921	Projects	PVS Net - Procard Charges		QUINN FLAG	608.40		608.40	Inappropriate
NOV-05	0921	Projects	PVS Net - Procard Charges		RAINBOW CRAIG MINI MAR	28.93		28.93	Inappropriate - Business Meal

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
JAN-06	0921	Projects	PVS Net - Procard Charges		RAMADA EXPRESS CSN CGE	150.00		150.00	Inappropriate - Employee Appreciation
APR-06	0921	Projects	PVS Net - Procard Charges		RED ROBIN	74.65		74.65	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		RUBY TUESDAY #4574	124.61		124.61	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00002SC9	25.61		25.61	Inappropriate - Employee Meeting
APR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	21.30		21.30	Inappropriate - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	147.10		147.10	Inappropriate - Employee Appreciation BBQ
DEC-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	117.99		117.99	Inappropriate - Employee Meeting
JUL-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	24.46		24.46	Inappropriate - Employee Meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018879	27.24		27.24	Inappropriate - Employee Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00018SC9	57.63		57.63	Inappropriate - Employee Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172	52.32		52.32	Inappropriate - Employee Appreciation BBQ
OCT-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172	27.38		27.38	Inappropriate - Employee Meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020172	56.12		56.12	Inappropriate - Employee Meeting
APR-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020289	25.27		25.27	Inappropriate - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020SC9	11.88		11.88	Inappropriate - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		SANDY'S	219.95		219.95	Inappropriate - Employee Meeting
AUG-05	0921	Projects	PVS Net - Procard Charges		SEARS DEALER 3089	682.09		682.09	Questionable Expense - Office Fridge
NOV-05	0921	Projects	PVS Net - Procard Charges		SEARS DEALER 3089	498.74		498.74	Questionable Expense - Office Fridge
AUG-05	0921	Projects	PVS Net - Procard Charges		SHERYL'S HALLMARK #2	7.54		7.54	Inappropriate - Sympathy Card
JUN-06	0921	Projects	PVS Net - Procard Charges		SHORT STOP MINI MARKET	4.75		4.75	Inappropriate - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		SHUGRUES RESTAURANT	50.00		50.00	Inappropriate - Employee Recognition
JUN-06	0921	Projects	PVS Net - Procard Charges		SHUGRUES RESTAURANT	137.95		137.95	Inappropriate - HR Related
AUG-05	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU	126.52		126.52	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU	164.34		164.34	Excessive - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		SILVER SADDLE STEAKHOU	78.30		78.30	Excessive - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6	42.84		42.84	Inappropriate - Employee Meeting
JUN-06	0921	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6	20.93		20.93	Inappropriate - Employee Meeting
NOV-05	0921	Projects	PVS Net - Procard Charges		STARBUCKS	6.51		6.51	Inappropriate - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		STARBUCKS USA 00069Q48	4.04		4.04	Inappropriate - Business Meal
SEP-05	0921	Projects	PVS Net - Procard Charges		STARBUCKS USA 00088Q48	5.51		5.51	Inappropriate - Business Meal
AUG-05	0921	Projects	PVS Net - Procard Charges		SUBWAY 16276	70.86		70.86	Inappropriate - Employee Appreciation BBQ
NOV-05	0921	Projects	PVS Net - Procard Charges		SUNSET STN HOTEL FD	4.95		4.95	Out-Of-State Expense?
OCT-05	0921	Projects	PVS Net - Procard Charges		SUNSET STN SUNST CAFE	16.93		16.93	Out-Of-State Expense?
SEP-05	0921	Projects	PVS Net - Procard Charges		TEQUILA CHARLIE'S	131.59		131.59	Excessive - Business Meal
JUN-06	0921	Projects	PVS Net - Procard Charges		TERRIBLES #148	14.37		14.37	Inappropriate - Employee Meeting
SEP-05	0921	Projects	PVS Net - Procard Charges		TEXAS ROADHOUSE #2204	121.91		121.91	Excessive - Business Meal
APR-06	0921	Projects	PVS Net - Procard Charges		THE HOME DEPOT #0416	746.96		746.96	Inappropriate - Office BBQ
SEP-05	0921	Projects	PVS Net - Procard Charges		THE OLIVE GARD00010959	50.32		50.32	Excessive - Business Meal
OCT-05	0921	Projects	PVS Net - Procard Charges		TOMATO CAFE	50.96		50.96	Excessive - Business Meal
DEC-05	0921	Projects	PVS Net - Procard Charges		TONTO APCHE CSNO MZTZL	14.15		14.15	Questionable Expense?
NOV-05	0921	Projects	PVS Net - Procard Charges		UNITED WAY OF GREATER	100.00		100.00	**Sponsorship - UNSE Agrees To Remove**
SEP-05	0921	Projects	PVS Net - Procard Charges		USA CHARTER BUS	891.25		891.25	Inappropriate
AUG-05	0921	Projects	PVS Net - Procard Charges		WALGREEN 00035Q39	17.27		17.27	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00052Q39	37.63		37.63	Office Supplies ?
FEB-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00076Q39	4.08		4.08	Office Supplies ?
MAY-06	0921	Projects	PVS Net - Procard Charges		WALGREEN 00076Q39	10.73		10.73	Office Supplies ?
DEC-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	22.55		22.55	Office Supplies ?
FEB-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	13.97		13.97	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	36.03		36.03	Office Supplies ?
NOV-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #1324 SE2	97.28		97.28	Office Supplies ?
JUN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #1364	17.18		17.18	Office Supplies ?
AUG-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	196.19		196.19	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	538.88		538.88	Office Supplies ?
MAR-06	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	13.46		13.46	Office Supplies ?
NOV-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	67.87		67.87	Office Supplies ?
SEP-05	0921	Projects	PVS Net - Procard Charges		WAL-MART #2051 SE2	34.65		34.65	Office Supplies ?
AUG-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	127.58		127.58	Office Supplies ?

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0921

GL Period	FERC	Query Source	PA Transaction Source	Gl JE Name	PA Expenditure Comment	DR	CR	Net Amount	RUCO'S COMMENT
FEB-06	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	80.46		80.46	Office Supplies ?
JAN-06	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	54.67		54.67	Office Supplies ?
JUL-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	10.50		10.50	Office Supplies ?
NOV-05	0921	Projects	PVS Net - Procard Charges		WM SUPERCENTER SE2	200.92		200.92	Office Supplies ?
APR-06	0921	Projects	PVS Net - Procard Charges		ZIVAZ	51.43		51.43	Excessive - Business Meal
								21,320.24	

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0923

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	PA Expenditure Comment	Invoice Number	DR	CR	Net Amount	RUCO'S COMMENT
FEB-06	0923	Projects	PVS Net - Procard Charges		AMZ*SUPERSTORE		54.83		54.83	Office Supplies?
JUN-06	0923	Projects	PVS Net - Procard Charges		BELLA DONNA RESTAURANT		62.07		62.07	Excessive - Business Meal
NOV-05	0923	Projects	PVS Net - Procard Charges		CINNABON		8.25		8.25	Inappropriate - Employee Training
FEB-06	0923	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LL	CA11906	1,953.13		976.57	2-Year Amortization
FEB-06	0923	Payables		Purchase Invoices USD	DANCES WITH OPPORTUNITY LL	CA22206	1,990.63		995.32	2-Year Amortization
APR-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4749208-50	1,106.46		1,106.46	Inappropriate - Drinking Water
AUG-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3378780-50	415.80		415.80	Inappropriate - Drinking Water
JAN-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4623406-50	337.87		337.87	Inappropriate - Drinking Water
JUL-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3064550-50	964.73		964.73	Inappropriate - Drinking Water
JUN-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	106877	789.57		789.57	Inappropriate - Drinking Water
MAR-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4742326-50	27.04		27.04	Inappropriate - Drinking Water
MAY-06	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4756016-50	574.94		574.94	Inappropriate - Drinking Water
NOV-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4283463-50	608.92		608.92	Inappropriate - Drinking Water
OCT-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	4053444-50	829.62		829.62	Inappropriate - Drinking Water
OCT-05	0923	Payables		Purchase Invoices USD	DS WATERS OF AMERICA INC	3701642-50	1,309.22		1,309.22	Inappropriate - Drinking Water
NOV-05	0923	Projects	PVS Net - Procard Charges		EDGEWATER HOTEL F/B		58.82		58.82	Out-Of-State Expense?
APR-06	0923	Projects	PVS Net - Procard Charges		FTD*SUTCLIFFE FLORAL		21.62		21.62	Office Supplies?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO ADV DEP		126.44		126.44	Out-Of-State Expense?
JUL-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO FOOD &		19.34		19.34	Out-Of-State Expense?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO FOOD &		22.28		22.28	Out-Of-State Expense?
JUL-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO LAUGHLI		83.93		83.93	Out-Of-State Expense?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO LAUGHLI		245.57		245.57	Out-Of-State Expense?
NOV-05	0923	Projects	PVS Net - Procard Charges		HARRAHS CASINO RETAIL		2.00		2.00	Out-Of-State Expense?
DEC-05	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		22.03		22.03	Inappropriate - Business Meal
FEB-06	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		18.70		18.70	Inappropriate - Business Meal
MAY-06	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		17.77		17.77	Inappropriate - Business Meal
NOV-05	0923	Projects	PVS Net - Procard Charges		HOUSE OF BREAD		20.65		20.65	Inappropriate - Business Meal
JUN-06	0923	Projects	PVS Net - Procard Charges		LOWNS COSTUMES AND NOV		37.50		37.50	**Inappropriate - UNSE Agrees To Remove**
JUL-05	0923	Projects	PVS Net - Procard Charges		LUXOR PYRAMID CAFE		22.00		22.00	Out-Of-State Expense?
SEP-05	0923	Projects	PVS Net - Procard Charges		MAIN STREET CATERING		178.98		178.98	Inappropriate - Employee Meeting
APR-06	0923	Projects	PVS Net - Procard Charges		MARRIOTT HOTELS WEST L		151.52		151.52	Out-Of-State Expense?
APR-06	0923	Projects	PVS Net - Procard Charges		MERRIBELL CORPORATION		28.93		28.93	Inappropriate - Safety Plaque
MAR-06	0923	Projects	PVS Net - Procard Charges		MERRIBELL CORPORATION		62.08		62.08	Inappropriate - Safety Plaque
DEC-05	0923	Projects	PVS Net - Procard Charges		MOHAVE COMMUNITY C		70.00		70.00	**Sponsorship - UNSE Agrees To Remove**
DEC-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00046547	3,824.30		764.86	Removing 20 % For Lobbying Activities
DEC-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00046571	3,824.30		764.86	Removing 20 % For Lobbying Activities
JAN-06	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00046839	3,824.30		764.86	Removing 20 % For Lobbying Activities
JUL-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0021660-IN	5,004.89		1,000.98	Removing 20 % For Lobbying Activities
JUL-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0021788-IN	5,004.89		1,000.98	Removing 20 % For Lobbying Activities
MAR-06	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0047740	7,648.60		1,529.72	Removing 20 % For Lobbying Activities
NOV-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00045422	3,824.30		764.86	Removing 20 % For Lobbying Activities
OCT-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	00044934	3,824.30		764.86	Removing 20 % For Lobbying Activities
SEP-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0022010-IN	3,824.30		764.86	Removing 20 % For Lobbying Activities
SEP-05	0923	Payables		Purchase Invoices USD	NORTHWEST PUBLIC POWER ASS	0022150-IN	3,824.30		764.86	Removing 20 % For Lobbying Activities
SEP-05	0923	Projects	PVS Net - Procard Charges		OPEN ROAD TOURES INC		125.00		125.00	Inappropriate
APR-06	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		106.11		106.11	Excessive - Business Meal
MAR-06	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		15.31		15.31	Inappropriate - Business Meal
SEP-05	0923	Projects	PVS Net - Procard Charges		OUR DAILY BREAD		26.63		26.63	Inappropriate - Business Meal
JUL-05	0923	Projects	PVS Net - Procard Charges		PASTO		103.52		103.52	Excessive - Business Meal
SEP-05	0923	Projects	PVS Net - Procard Charges		SAFEWAY STORE00020289		11.54		11.54	Inappropriate - Kitchen Supplies
NOV-05	0923	Projects	PVS Net - Procard Charges		SMITHS FOOD #4190 SS6		62.16		62.16	Inappropriate - Employee Meeting
OCT-05	0923	Projects	PVS Net - Procard Charges		WESTIN KIERLAND RESTIP		136.18		136.18	Questionable Expense?
JUL-05	0923	Projects	PVS Net - Procard Charges		WINDROCK AVIATION		332.00		332.00	Questionable Expense?
SEP-05	0923	Projects	PVS Net - Procard Charges		YAVAPAI BUS TOURS		235.00		235.00	Questionable Expense?
									20,310.51	

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0930

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	tui	Vendor Name	Invoice Number	DR	CR	Net Amount		RUCO'S COMMENT
APR-06	0930	Projects	PVS Net - Procard Charges			ALBERTSONS #1027 S9H		12.27		12.27	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Payables		Purchase Invoices USD		ARIZONA INDEPENDENT SCHEDULING ADMINISTF	2006-25	250.00		250.00	R	Does Not Benefit Ratepayers - Retail Competition
JUL-05	0930	Payables		Purchase Invoices USD		ARIZONA UTILITY INVESTORS ASSOC	072705 500000	2,500.00		2,500.00	R	**Does Not Benefit Ratepayers - UNSE Agrees To Remove**
JUL-05	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		94.78		94.78	R	Inappropriate - Employee Recognition
OCT-05	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		50.00		50.00	R	Inappropriate - Employee Recognition
JAN-06	0930	Projects	PVS Net - Procard Charges			BARLEY BROTHERS BREWER		98.11		98.11	R	Inappropriate - Employee Recognition
AUG-05	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		10.17		10.17	R	Inappropriate - Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		7.20		7.20	R	Inappropriate - Safety Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			BASHAS #116 SYW		13.76		13.76	R	Inappropriate - Safety Meeting
OCT-05	0930	Projects	PVS Net - Procard Charges			BASHAS 60 SYW		4.54		4.54	R	Inappropriate - Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			BLACK BEAR DINER N		287.78		287.78	R	Inappropriate - Employee Recognition
NOV-05	0930	Payables		Purchase Invoices USD		BOYS & GIRLS CLUB OF NOGALES	110805 3500	35.00		35.00	R	**Sponsorship - UNSE Agrees To Remove**
JUL-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	15944	3,712.50		1,856.25	R	2-Year Amortization
SEP-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	16252	974.00		487.00	R	2-Year Amortization
SEP-05	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	16347	4,677.75		2,338.88	R	2-Year Amortization
MAY-06	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	17808	3,712.50		1,856.25	R	2-Year Amortization
JUN-06	0930	Payables		Purchase Invoices USD		BUSINESS TRAINING LIBRARY	18010	711.00		355.50	R	2-Year Amortization
JAN-06	0930	Projects	PVS Net - Procard Charges			CHA-BONES		191.25		191.25	R	Inappropriate - 15 Employees Lunch
FEB-06	0930	Projects	PVS Net - Procard Charges			CHILI'S GRI04900010496		79.53		79.53	R	Excessive - Business Meal
JUN-06	0930	Payables		Purchase Invoices USD		CITY OF BULLHEAD CITY	062506 5417	54.17		54.17	R	Dues
JUN-06	0930	Projects	PVS Net - Procard Charges			DIAMOND BACKS MERCHNDI		47.57		47.57	R	**Inappropriate - UNSE Agrees To Remove**
JUL-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		107.68		107.68	R	Inappropriate - Safety Meeting
NOV-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		116.89		116.89	R	Inappropriate - Safety Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		48.39		48.39	R	Inappropriate - Safety Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		103.36		103.36	R	Inappropriate - Safety Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		101.74		101.74	R	Inappropriate - Safety Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			DONUT DEPOT		77.52		77.52	R	Inappropriate - Safety Meeting
JUL-05	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000025467C	24,071.00		4,814.20	R	Removing 20 % For Lobbying Activities
JAN-06	0930	Payables		Purchase Invoices USD		EDISON ELECTRIC INSTITUTE	1-000038367	2,801.90		560.38	R	Removing 20 % For Lobbying Activities
NOV-05	0930	Projects	PVS Net - Procard Charges			ELEPHANT BAR # 219		173.56		173.56	R	Excessive - Business Meal
JUL-05	0930	Projects	PVS Net - Procard Charges			EXPRESS STOP		11.65		11.65	R	Inappropriate - Business Related
NOV-05	0930	Projects	PVS Net - Procard Charges			FIREBIRDS OF CHANDLER		168.20		168.20	R	Excessive - Business Meal
APR-06	0930	Projects	PVS Net - Procard Charges			FLAMINGO ALTA VILLA		59.64		59.64	R	Out-Of-State Expense?
FEB-06	0930	Projects	PVS Net - Procard Charges			FRESH PRODUCE ASSOC		250.00		250.00	R	Dues
SEP-05	0930	Payables		Purchase Invoices USD		GOLDEN VALLEY CHAMBER OF COMMERCE	JULY 2005	35.00		35.00	R	Dues
OCT-05	0930	Payables		Purchase Invoices USD		GOLDEN VALLEY CHAMBER OF COMMERCE	07/2005	35.00		35.00	R	Dues
OCT-05	0930	Projects	PVS Net - Procard Charges			H.L.A FRONT DESK #1		229.61		229.61	R	Travel Expense?
APR-06	0930	Projects	PVS Net - Procard Charges			HMS HOST-LAS-AIRPT#241		7.29		7.29	R	Out-Of-State Expense?
OCT-05	0930	Projects	PVS Net - Procard Charges			HOOTERS OF OVERLAND PA		58.87		58.87	R	Out-Of-State Expense?
APR-06	0930	Projects	PVS Net - Procard Charges			HOTEL CONTESSA-HOTEL		1,330.98		1,330.98	R	Out-Of-State Expense?
JAN-06	0930	Projects	PVS Net - Procard Charges			IHOP #3033		80.59		80.59	R	Inappropriate - 7 Employees Lunch
MAR-06	0930	Projects	PVS Net - Procard Charges			JAVELINA CANTINA		56.96		56.96	R	Inappropriate - 4 Employees Lunch
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN CHAMBER OF COMMERCE	207916A	325.00		325.00	R	Dues
MAY-06	0930	Projects	PVS Net - Procard Charges			KINGMAN DELI, THE		81.42		81.42	R	Excessive
OCT-05	0930	Payables		Purchase Invoices USD		KINGMAN MOHAVE LIONS CLUB	1376	60.00		60.00	R	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN ROTARY CLUB	102605 12500	125.00		125.00	R	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KINGMAN ROUTE 66 ROTARY CLUB	100105 13250	132.50		132.50	R	Dues
JUN-06	0930	Payables		Purchase Invoices USD		KINGMAN ROUTE 66 ROTARY CLUB	060506 12500	125.00		125.00	R	Dues
AUG-05	0930	Payables		Purchase Invoices USD		KINGSMEN	081505 12500	125.00		125.00	R	Dues
NOV-05	0930	Payables		Purchase Invoices USD		KIWANIS CLUB OF LAKE HAVASU	110305 66600	666.00		666.00	R	Dues
DEC-05	0930	Projects	PVS Net - Procard Charges			KMART 00037077		30.44		30.44	R	Supplies?
MAY-06	0930	Projects	PVS Net - Procard Charges			LAKE HAVASU CHAMBER OF		505.00		505.00	R	Dues
APR-06	0930	Projects	PVS Net - Procard Charges			LOS PRIMOS BAR & GRILL		96.21		96.21	R	Inappropriate - 7 Employees OT Meal
DEC-05	0930	Projects	PVS Net - Procard Charges			MARIE CALLENDER'S #245		567.80		567.80	R	Excessive - March Of Dimes
AUG-05	0930	Projects	PVS Net - Procard Charges			MCCARRAN INT L AVIATIO		62.00		62.00	R	Out-Of-State Expense?
OCT-05	0930	Projects	PVS Net - Procard Charges			MCCARRAN INT L AVIATIO		41.00		41.00	R	Out-Of-State Expense?
AUG-05	0930	Payables		Purchase Invoices USD		MINKUS ADVERTISING SPECIALTIES	052917	536.50		536.50	R	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0930	Payables		Purchase Invoices USD		MINKUS ADVERTISING SPECIALTIES	052918	1,118.00		1,118.00	R	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0930	Payables		Purchase Invoices USD		MOHAVE MUSEUM OF HISTORY & ARTS	080305 20000	200.00		200.00	R	**Inappropriate - UNSE Agrees To Remove**
NOV-05	0930	Projects	PVS Net - Procard Charges			N AWLINS ON MONTEZUMA		340.71		340.71	R	**Inappropriate - UNSE Agrees To Remove**
JUN-06	0930	Projects	PVS Net - Procard Charges			NATURAL TEASE SPORTWEA		99.87		99.87	R	**Inappropriate - UNSE Agrees To Remove**
JUN-06	0930	Payables		Purchase Invoices USD		NOGALES-SANTA CRUZ CHAMBER OF COMMERCI	060906 6000	60.00		60.00	R	Dues
JUL-05	0930	Projects	PVS Net - Procard Charges			NORTHWEST PUBLIC POW		210.00		210.00	R	Dues
NOV-05	0930	Projects	PVS Net - Procard Charges			OUTBACK #0317		142.86		142.86	R	Excessive - 2 Employees Meals
OCT-05	0930	Projects	PVS Net - Procard Charges			PIZZA HUT 21200Q34		168.89		168.89	R	Inappropriate - 6 Employees Meals
FEB-06	0930	Projects	PVS Net - Procard Charges			PIZZA HUT #00942700Q34		119.66		119.66	R	Inappropriate - Refreshments
FEB-06	0930	Projects	PVS Net - Procard Charges			PLUSHLAND INC		174.00		174.00	R	**Inappropriate - UNSE Agrees To Remove**
AUG-05	0930	Projects	PVS Net - Procard Charges			PRESCOTT CONVENTION CT		171.74		171.74	R	Questionable Expense - UES Mentoring?
JUN-06	0930	Projects	PVS Net - Procard Charges			PRONTO MARKET		27.01		27.01	R	Inappropriate - Refreshments
MAR-06	0930	Projects	PVS Net - Procard Charges			R A W SPORTS		50.00		50.00	R	Inappropriate - Employee Appreciatiopn
JUN-06	0930	Projects	PVS Net - Procard Charges			R A W SPORTS		200.53		200.53	R	**Inappropriate - UNSE Agrees To Remove**
APR-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00002162		32.21		32.21	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00012294		250.42		250.42	R	**Inappropriate - UNSE Agrees To Remove**
NOV-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		23.76		23.76	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		31.01		31.01	R	Inappropriate - Refreshments For Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		30.79		30.79	R	Inappropriate - Refreshments For Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		85.76		85.76	R	Inappropriate - Refreshments For Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			SAFEWAY STORE00018879		28.76		28.76	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SANDY'S		513.24		513.24	R	Questionable Expense - Employee Lunches
FEB-06	0930	Projects	PVS Net - Procard Charges			SANDY'S		65.35		65.35	R	Questionable Expense - Employee Lunches

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EXHIBIT B

WORKPAPERS FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
FERC ACCOUNT CODE 0930

GL Period	FERC	Query Source	PA Transaction Source	GI JE Name	tui	Vendor Name	Invoice Number	DR	CR	Net Amount		RUCO'S COMMENT
APR-06	0930	Projects	PVS Net - Procard Charges			SANDY'S		133.73		133.73	R	Questionable Expense - Employee Lunches
JUL-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		52.88		52.88	R	Inappropriate - Refreshments For Meeting
AUG-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		60.73		60.73	R	Inappropriate - Refreshments For Meeting
SEP-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		45.88		45.88	R	Inappropriate - Refreshments For Meeting
OCT-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		45.89		45.89	R	Inappropriate - Refreshments For Meeting
NOV-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		64.44		64.44	R	Inappropriate - Refreshments For Meeting
DEC-05	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		41.41		41.41	R	Inappropriate - Refreshments For Meeting
JAN-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		29.44		29.44	R	Inappropriate - Refreshments For Meeting
FEB-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		38.23		38.23	R	Inappropriate - Refreshments For Meeting
MAR-06	0930	Projects	PVS Net - Procard Charges			SMITHS FOOD #4188 SS6		43.90		43.90	R	Inappropriate - Refreshments For Meeting
MAY-06	0930	Projects	PVS Net - Procard Charges			SOTO'S P/K OUTPOST		91.23		91.23	R	Questionable Expense - Employee Meals
APR-06	0930	Projects	PVS Net - Procard Charges			STEERS AND BEERS		62.56		62.56	R	Questionable Expense - 2 Employee Meals
FEB-06	0930	Projects	PVS Net - Procard Charges			TERRIBLES #148		14.98		14.98	R	Inappropriate - Refreshments For Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			TERRIBLES #148		23.67		23.67	R	Inappropriate - Refreshments For Meeting
APR-06	0930	Projects	PVS Net - Procard Charges			TEXAS LAND & CATTLE#71		71.79		71.79	R	Out-Of-State Expense?
JUN-06	0930	Projects	PVS Net - Procard Charges			THE HOME DEPOT #0416		323.26		323.26	R	**Questionable Expense - UNSE Agrees To Remove**
DEC-05	0930	Projects	PVS Net - Procard Charges			THE HOME DEPOT 403		30.73		30.73	R	**Questionable Expense - UNSE Agrees To Remove**
NOV-05	0930	Projects	PVS Net - Procard Charges			TOMATO CAFE		35.30		35.30	R	Questionable Expense - 3 Employee Lunches
FEB-06	0930	Projects	PVS Net - Procard Charges			VILLA S FOOD MARKET		40.67		40.67	R	Inappropriate - Pot Luck For Retirement
MAY-06	0930	Projects	PVS Net - Procard Charges			VILLA S FOOD MARKET		9.37		9.37	R	Inappropriate - Pot Luck For Retirement
JUL-05	0930	Projects	PVS Net - Procard Charges			WAL MART		45.50		45.50	R	Inappropriate - Gatorade
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL MART		36.66		36.66	R	Inappropriate - Gatorade
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1324 SE2		47.55		47.55	R	Office Supplies?
JUL-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364		24.90		24.90	R	Inappropriate - Gatorade
AUG-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364		23.70		23.70	R	Inappropriate - Gatorade
SEP-05	0930	Projects	PVS Net - Procard Charges			WAL-MART #1364		41.11		41.11	R	Inappropriate - Gatorade
JUN-06	0930	Projects	PVS Net - Procard Charges			WAL-MART #2051 SE2		262.83		262.83	R	Inappropriate - March Of Dimes
SEP-05	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2		1.78		1.78	R	Inappropriate - Air Freshners For Fridge
FEB-06	0930	Projects	PVS Net - Procard Charges			WM SUPERCENTER SE2		25.43		25.43	R	Inappropriate
										28,450.51		

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OPERATING INCOME ADJUSTMENT NO. 18
OVERHEAD LINE MAINTENANCE

LINE NO.	ACCT NO.	ACCOUNT DESCRIPTION	(A) COMPANY DATA PER RUCO D.R. 2.12	(B) RUCO ADJUSTMENT PER CPI INFLATION	(C) RUCO ADJUSTMENT
1	593	2003 Year-End Overhead Line Maintenance	$ 334,755	$ 366,775	
2	593	2004 Year-End Overhead Line Maintenance	916,869	978,511	
3	593	2005 Year-End Overhead Line Maintenance	1,136,346	1,173,312	
4	593	2006 Year-End Overhead Line Maintenance	1,010,101	1,010,101	
5		Four Year Total (Sum Of Lines 1 Thru 4)	$ 3,398,070	$ 3,528,699	
6		Average (Line 5 / 4Years)		$ 882,175	
7	593	Test-Year Ending June 30, 2006 Overhead Line Maintenance (Per 2		$ 1,149,853	
8		Difference (Line 6 - Line 7)			$ (267,678)
9		RUCO Adjustment (Line 8) (See RLM-8, Pages 5 & 6, Column (S))			$ (267,678)

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OPERATING INCOME ADJUSTMENT NO. 19
CUSTOMER SERVICE COST ALLOCATION

LINE NO.	ACCT NO.	ACCOUNT DESCRIPTION	(A) UNS GAS AS FILED	(B) ALLOCATION FACTOR	(C) RUCO AS ADJUSTED
1	403	Depreciation Expense	$ 30,202	3.23%	$ (2,156)
2	408	Taxes Other Than Income Tax	33,577	3.59%	(2,397)
3	903	Customer Records & Collection Expenses	633,713	67.71%	(45,230)
4	920	A & G - Salaries	32,869	3.51%	(2,346)
5	921	Office Supplies & Expenses	14,416	1.54%	(1,029)
6	922	Administrative Expenses Transferred	172	0.02%	(12)
7	923	Outside Services	3,307	0.35%	(236)
8	924	Property Insurance	1,717	0.18%	(123)
9	925	Injuries & Damages	379	0.04%	(27)
10	926	Pensions & Benefits	185,531	19.82%	(13,242)
11		TOTAL	$ 935,884	100.00%	$ (66,797)
12		RUCO Adjustment (See RLM-8, Pages 5 & 6, Column (T) For Distribution)			$ (66,797)

Company Determined Allocation Percentages

LINE NO.	2005	UNS GAS	UNS ELECTRIC	TOTAL UES
13	May	20.20%	13.90%	34.10%
14	June	18.90%	13.00%	31.90%
15	July	16.80%	12.20%	29.00%
16	August	15.90%	12.30%	28.20%
17	September	16.40%	13.50%	29.90%
18	October	18.70%	14.70%	33.40%
19	November	19.90%	15.20%	35.10%
20	December	20.70%	15.50%	36.20%
21	Average	18.44%	13.79%	32.23%

RUCO Calculation Of Adjustment

LINE NO.	UNS	MONTHLY COSTS PER RUCO D.R. 2.12 TOTAL UNS	RUCO CALCULATED ANNUAL COSTS	13.79% ALLOCATED TO UNS ELECTRIC
	Pre Consolidation			
22	Estimated UNS Labor and Long Distance:	$ 321,640	$ 3,859,684	$ 532,154
	Post Consolidation			
23	UNS Labor and Long Distance Cost:	$ 362,013	$ 4,344,160	$ 598,951
24	Difference Between Pre & Post Consolidation			$ (66,797)
25	RUCO Adjustment To Test-Year Customer Service Cost Allocation			$ (66,797)

References:
Column (A): Company UNS Gas Workpapers
Column (B): Individual Account Allocation Based On Percentage Of Each UNS Gas Account To Total
Column (C): RUCO Adjustment To Customer Service Cost Allocated By Allocation Factors In Column (B)

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OPERATING INCOME ADJUSTMENT NO. 22
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-7, Column (C), Line 11 + Line 9	$ 13,600,927
	LESS:		
2	Arizona State Tax	Line 11	(577,051)
3	Interest Expense	Note (A) Line 22	(5,319,481)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 7,704,395
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 9	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 2,619,494
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 13,600,927
	LESS:		
8	Interest Expense	Note (A) Line 22	(5,319,481)
9	State Taxable Income	Line 7 + Line 8	$ 8,281,447
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 577,051
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 2,619,494
13	State Income Tax Expense	Line 11	577,051
14	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 3,196,546
15	Total Income Tax Expense Per Company Filing (Schedule C-1)		1,837,339
16	Difference	Line 14 - Line 15	$ 1,359,207
17	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 8, Pages 5 & 6, Column (AC))	Line 16	$ 1,359,207

NOTE (A):
Interest Synchronization:

LINE NO.	DESCRIPTION	AMOUNT
18	Adjusted Rate Base (Schedule RLM-3, Column (C), Line 16)	$ 128,777,882
19	Weighted Cost Of Debt (Schedule RLM-16, Column (F), Line 1 + Line 2)	4.13%
20	Interest Expense (Line 20 X Line 21)	$ 5,319,481

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RATE DESIGN AND PROOF OF RUCO RECOMMENDED REQUIRED REVENUE

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) RUCO ADJ'D BILL DETERM'TS		(C) RUCO ADJ'D RATES AND CHARGES		(D) RUCO PROPOSED REVENUE CALCULATION		(E) RUCO PROPOSED REVENUE BY CUST. CLASS
	Residential Service	R-01							
1	Customer Charge per Month		929,088	$	7.65	$	7,108,311		
2	Energy Charge, First 400 kWhs		320,682,178	$	0.01207		3,869,707		
3	Energy Charge, All Additional kWhs		481,023,266	$	0.02163		10,404,947		
4	Base Power Supply Charge, All kWhs		801,705,444	$	0.07381		59,173,596		
5	SUB-TOTAL RESIDENTIAL SERVICE							$	80,556,562
	Small General Service	GS-10							
6	Customer Charge per Month		89,914	$	11.47627	$	1,031,878		
7	Energy Charge, First 400 kWhs		36,412,013	$	0.02656		967,031		
8	Energy Charge, All Additional kWhs		54,618,021	$	0.03612		1,972,993		
9	Base Power Supply Charge, All kWhs		91,030,034	$	0.07168		6,524,670		
10	SUB-TOTAL SMALL GENERAL SERVICE							$	10,496,571
	Large General Service	LGS							
11	Customer Charge per Month		24,301	$	10.61555	$	257,969		
12	Demand Charge, Per kW		1,426,880	$	10.04174		14,328,356		
13	Energy Charge, Per kWh		491,246,281	$	0.00717		3,522,138		
14	Base Power Supply Charge, All kWhs		491,246,281	$	0.06347		31,177,289		
15	Total Large General Service					$	49,285,752		
	Large General Service - TOU	LGS							
16	Customer Charge per Month		120	$	15.30170	$	1,836		
17	Demand Charge, Per kW		11,084	$	10.04174		111,303		
18	Energy Charge, Per kWh		2,903,715	$	0.00717		20,819		
19	Base Power Supply Charge, All kWhs		2,903,715	$	0.06347		184,286		
20	Total Large General Service - TOU					$	318,244		
21	SUB-TOTAL LARGE GENERAL SERVICE							$	49,603,996
	Large Power Service - < 69KV	LPS							
22	Customer Charge per Month		75	$	349.06996	$	26,180		
23	Demand Charge, Per kW		81,047	$	20.59035		1,668,786		
25	Base Power Supply Charge, All kWhs		41,382,039	$	0.05040		2,085,812		
26	Total Large General Service - < 69KV					$	3,780,778		
	Large Power Service - > 69KV	LPS							
27	Customer Charge per Month		69	$	382.54242	$	26,395		
28	Demand Charge, Per kW		288,524	$	11.98314		3,457,424		
30	Base Power Supply Charge, All kWhs		157,244,717	$	0.05040		7,925,730		
31	Total Large General Service - > 69KV					$	11,409,549		
32	SUB-TOTAL LARGE POWER SERVICE							$	15,190,326
	Interruptible Power Service	IPS							
33	Customer Charge per Month		235	$	10.61555	$	2,495		
34	Demand Charge, Per kW		63,585	$	3.34725		212,835		
35	Energy Charge, Per kWh		17,598,914	$	0.01747		307,466		
37	Base Power Supply Charge, All kWhs		17,598,914	$	0.05251		924,198		
38	Total Interruptible Service								
39	SUB-TOTAL INTERUPTIBLE SERVICE							$	1,446,992
	Lighting Dusk To Dawn Service - O/H Service	LTG							
40	Existing Wood Pole		39,277	$	-	$	-		
41	New 30' Wood Pole (Class 6)		8,220	$	4.30360		35,376		
42	New 30' Metal Or Fiberglass		2,385	$	8.62633		20,574		
	Lighting Dusk To Dawn Service - U/G Service								
43	Existing Wood Pole		686	$	2.15180		1,476		
44	New 30' Wood Pole (Class 6)		347	$	6.46497		2,243		
45	New 30' Metal Or Fiberglass		7,646	$	10.77813		82,410		
46	Per Watt		7,866,778	$	0.05956		468,567		
48	SUB-TOTAL LIGHTING DUSK TO DAWN SERVICE							$	610,646
49	TOTAL REVENUE PER RUCO BILL DETERMINENTS							$	157,905,093
50	Sales For Resale								246,016
51	Other Operating Revenue								1,637,662
52	TOTAL PROPOSED REVENUE							$	159,788,771
53	Proposed Annual Revenue Requirement							$	159,788,771
54	Difference							$	0

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)	(E)	(F)
		PRESENT REVENUE		COMPANY PROPOSED		RUCO PROPOSED	
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 81,247,060	51.48%	$ 84,232,815	51.02%	$ 80,556,562	51.02%
2	OTHER	$ 76,580,097	48.52%	$ 80,878,384	48.98%	$ 77,348,532	48.98%
3	TOTAL	$ 157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,905,093	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	7,403,038	4.69%	8,989,479	5.44%	$ 8,597,143	5.44%
5	VARIABLE REVENUE	150,424,119	95.31%	156,121,720	94.56%	$ 149,307,951	94.56%
6	TOTAL	157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,905,093	100.00%
	RESIDENTIAL RATE DESIGN	PRESENT RATES		COMPANY PROPOSED		RUCO PROPOSED	
	Residential Service - Mohave County						
7	Customer Charge per Month	$ 6.50		$ 8.00		$ 7.65	
8	Energy Charge, First 400 kWhs	$ 0.07490		$ 0.0126178		$ 0.01207	
9	Energy Charge, All Additional kWhs	$ 0.07490		$ 0.0226180		$ 0.02163	
10	PPFAC Charge	$ 0.018250					
11	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.07381	
	Residential Service - Santa Cruz County						
12	Customer Charge per Month	$ 6.50		$ 8.00		$ 7.65	
13	Energy Charge, First 400 kWhs	$ 0.07930		$ 0.0126178		$ 0.01207	
14	Energy Charge, All Additional kWhs	$ 0.07930		$ 0.0226180		$ 0.02163	
15	PPFAC Charge	$ 0.018250					
16	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.07381	
	RESIDENTIAL BILL COMPARISONS						
	MONTHLY ELECTRIC BILLS AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	% OF AVERAGE MONTH USAGE OF 10,334 kWh	ACTUAL MONTH USAGE OF 10,334 kWh	PRESENT MONTHLY COST	RUCO PROP'D MONTHLY COST	RUCO PROP'D MONTHLY INCREASE	RUCO PROP'D MONTHLY % INCREASE
	Residential Service - Mohave County						
17	Customer Charge per Month	25.00%	2,584	$ 247.15	$ 250.40	$ 3.24	1.31%
18	Energy Charge, First 400 kWhs	50.00%	5,167	$ 487.81	$ 496.97	$ 9.16	1.88%
19	Energy Charge, All Additional kWhs	100.00%	10,334	$ 969.11	$ 990.11	$ 21.00	2.17%
20	PPFAC Charge	150.00%	15,501	$ 1,450.42	$ 1,483.25	$ 32.83	2.26%
21	Residential Service Base Power Supply Charge, All kWhs	200.00%	20,668	$ 1,931.72	$ 1,976.39	$ 44.67	2.31%
	Residential Service - Santa Cruz County						
22	Customer Charge per Month	25.00%	2,584	$ 258.52	$ 250.40	$ (8.12)	-3.14%
23	Energy Charge, First 400 kWhs	50.00%	5,167	$ 510.54	$ 496.97	$ (13.57)	-2.66%
24	Energy Charge, All Additional kWhs	100.00%	10,334	$ 1,014.58	$ 990.11	$ (24.47)	-2.41%
25	PPFAC Charge	150.00%	15,501	$ 1,518.62	$ 1,483.25	$ (35.37)	-2.33%
26	Residential Service Base Power Supply Charge, All kWhs	200.00%	20,668	$ 2,022.66	$ 1,976.39	$ (46.27)	-2.29%

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 5,000	$ -	$ 5,000	3.97%	6.36%	0.25%
2	Long-term Debt	$ 59,486	$ -	$ 59,486	47.18%	8.22%	3.88%
3	Preferred Stock	N/A	$ -	$ -	0.00%	0.00%	0.00%
4	Common Equity	$ 61,587	$ -	$ 61,587	48.85%	9.30%	4.54%
5	TOTAL CAPITAL	$ 126,073	$ -	$ 126,073	100.00%		
6	WEIGHTED COST OF CAPITAL						8.67%

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) + Column (B)
Column (D): Column (C), Line Item / Total Capital (L5)
Column (E): Testimony, WAR
Column (F): Column (D) X Column (E)

EXHIBIT
RUCO-6
Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT RATE DESIGN TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 12, 2007

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INTRODUCTION

A. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on June 28, 2007.

Q. What is the purpose of your additional direct testimony?

A. My additional direct testimony will address RUCO's rate design and prove that this rate design will produce RUCO's recommended revenue. Also, I have included an analysis of a typical residential bill.

To support RUCO's position in this additional direct testimony, I have prepared Schedules numbered RLM-16 and RLM-17.

RATE DESIGN

A. Please explain your contribution to RUCO's recommended rate designs.

A. As shown on Schedule RLM-16, I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts and energy consumed). After reviewing the Company's workpapers, I accepted UNS bill determinants as adjusted for weather normalization and customer annualization. An in-depth discussion of RUCO's proposed rate design is contained in the testimony of RUCO witness, Marylee Diaz Cortez. In summary, for residential customers, RUCO proposes a monthly basic service charge of $6.80 and energy charges of: $0.010731 for the first 400 kWh, $0.0192350 for all additional kWh and a base power supply charge of $0.077178.

Q. Please explain the elements of the rate design.

A. Schedule RLM-16 illustrates the elements of RUCO's rate design proposed by Ms. Diaz Cortez in her testimony, which are:

1. Provides a positive price signal to encourage energy efficient usage;
2. Is consistent with the Company's Cost of Service Study parameters;
3. Implements an inverted block (tiered) structure for residential and small commercial rates;

4. Eliminates separate rates for Mohave and Santa Cruz Counties and applies system-wide rates in both counties; and

5. Resets the beginning PPFAC to zero, by shifting all existing power supply costs to base rates.

PROOF OF RECOMMENDED REVENUE

A. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that RUCO's recommended rate design will produce the recommended required revenue as illustrated is presented on Schedule RLM-16.

TYPICAL BILL ANALYSIS

A. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for residential customers with various levels of usage is presented on Schedule RLM-17.

Q. Please provide an excerpt of RUCO's rate structure that illustrates RUCO's rate design goals as set forth in the testimony of Ms. Diaz Cortez which captures these fundamental changes in UNS's current rate design.

A. Schedule RLM-17 provides an extensive breakdown of the effects of RUCO's proposed rates on the R-01 Residential Customer. Below is a chart gleaned from Schedule RLM-17 comparing UNS' proposed rates to RUCO's proposed annual rates:

<u>UNS Proposed Rates and Charges</u>

Basic Monthly Service Charge	$8.00
Energy Charge (first 400 kWh)	$0.012617
Energy Charge (all additional kWh)	$0.022617
Base Power Supply Charge (all kWh)	$0.077178

<u>RUCO Proposed Rates and Charges</u>

Basic Monthly Service Charge	$6.80
Energy Charge (first 400 kWh)	$0.010731
Energy Charge (all additional kWh)	$0.019235
Base Power Supply Charge (all kWh)	$0.077178

RUCO's proposed rate design when compared to the Company's proposal:

1. Provides a clear price signal that increased consumption will increase a ratepayer's monthly bill and reduced consumption will lower a ratepayer's monthly bill in effort to promote conservation; and

2. Maintains the same historical percentage (51 percent Residential vs. 49 percent Other) of revenue recovery among classes of service in recognition of the Company's Cost of Service Study.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Test Year Ended June 30, 2006

RATE DESIGN AND PROOF OF RUCO RECOMMENDED REQUIRED REVENUE

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) RUCO ADJ'D BILL DETERM'TS	(C) RUCO ADJ'D RATES AND CHARGES	(D) RUCO PROPOSED REVENUE CALCULATION	(E) RUCO PROPOSED REVENUE BY CUST. CLASS
	Residential Service	R-01				
1	Customer Charge per Month		929,088	$ 6.80	$ 6,320,991	
2	Energy Charge, First 400 kWhs		320,682,178	$ 0.01073	3,441,096	
3	Energy Charge, All Additional kWhs		481,023,266	$ 0.01924	9,252,490	
4	Base Power Supply Charge, All kWhs		801,705,444	$ 0.07718	61,874,023	
5	SUB-TOTAL RESIDENTIAL SERVICE					$ 80,888,600
	Small General Service	GS-10				
6	Customer Charge per Month		89,914	$ 10.21	$ 917,586	
7	Energy Charge, First 400 kWhs		36,412,013	$ 0.02362	859,922	
8	Energy Charge, All Additional kWhs		54,618,021	$ 0.03212	1,754,463	
9	Base Power Supply Charge, All kWhs		91,030,034	$ 0.07495	6,822,428	
10	SUB-TOTAL SMALL GENERAL SERVICE					$ 10,354,399
	Large General Service	LGS				
11	Customer Charge per Month		24,301	$ 9.44	$ 229,396	
12	Demand Charge, Per kW		1,426,880	$ 8.93	12,741,340	
13	Energy Charge, Per kWh		491,246,281	$ 0.00638	3,132,024	
14	Base Power Supply Charge, All kWhs		491,246,281	$ 0.06636	32,600,086	
15	Total Large General Service				$ 48,702,846	
	Large General Service - TOU	LGS				
16	Customer Charge per Month		120	$ 13.61	$ 1,633	
17	Demand Charge, Per kW		11,084	$ 8.93	98,975	
18	Energy Charge, Per kWh		2,903,715	$ 0.00638	18,513	
19	Base Power Supply Charge, All kWhs		2,903,715	$ 0.06636	192,696	
20	Total Large General Service - TOU				$ 311,817	
21	SUB-TOTAL LARGE GENERAL SERVICE					$ 49,014,663
	Large Power Service - < 69KV	LPS				
22	Customer Charge per Month		75	$ 365.00	$ 27,375	
23	Demand Charge, Per kW		81,047	$ 24.75	2,005,913	
25	Base Power Supply Charge, All kWhs		41,382,039	$ 0.05270	2,180,999	
26	Total Large General Service - < 69KV				$ 4,214,287	
	Large Power Service - > 69KV	LPS				
27	Customer Charge per Month		69	$ 340.17	$ 23,472	
28	Demand Charge, Per kW		288,524	$ 10.66	3,074,478	
30	Base Power Supply Charge, All kWhs		157,244,717	$ 0.05270	8,287,426	
31	Total Large General Service - > 69KV				$ 11,385,375	
32	SUB-TOTAL LARGE POWER SERVICE					$ 15,599,662
	Interruptible Power Service	IPS				
33	Customer Charge per Month		235	$ 9.44	$ 2,218	
34	Demand Charge, Per kW		63,585	$ 2.98	189,261	
35	Energy Charge, Per kWh		17,598,914	$ 0.01554	273,411	
37	Base Power Supply Charge, All kWhs		17,598,914	$ 0.05491	966,374	
38	Total Interruptible Service					
39	SUB-TOTAL INTERUPTIBLE SERVICE					$ 1,431,264
	Lighting Dusk To Dawn Service - O/H Service	LTG				
40	Existing Wood Pole		39,277	$ -	$ -	
41	New 30' Wood Pole (Class 6)		8,220	$ 3.83	31,457	
42	New 30' Metal Or Fiberglass		2,385	$ 7.67	18,295	
	Lighting Dusk To Dawn Service - U/G Service					
43	Existing Wood Pole		686	$ 1.91	1,313	
44	New 30' Wood Pole (Class 6)		347	$ 5.75	1,995	
45	New 30' Metal Or Fiberglass		7,646	$ 9.58	73,282	
46	Per Watt		7,866,778	$ 0.06231	490,163	
48	SUB-TOTAL LIGHTING DUSK TO DAWN SERVICE					$ 616,505
49	TOTAL REVENUE PER RUCO BILL DETERMINENTS					$ 157,905,093
50	Sales For Resale					246,016
51	Other Operating Revenue					1,637,662
52	TOTAL PROPOSED REVENUE					$ 159,788,771
53	Proposed Annual Revenue Requirement					$ 159,788,771
54	Difference					$ 0

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)	(E)	(F)
		PRESENT REVENUE		COMPANY PROPOSED		RUCO PROPOSED	
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 81,247,060	51.48%	$ 84,232,815	51.02%	$ 80,888,600	51.23%
2	OTHER	$ 76,580,097	48.52%	$ 80,878,384	48.98%	$ 77,016,493	48.77%
3	TOTAL	$ 157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,905,093	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	7,403,038	4.69%	8,989,479	5.44%	$ 7,649,013	4.84%
5	VARIABLE REVENUE	150,424,119	95.31%	156,121,720	94.56%	$ 150,256,080	95.16%
6	TOTAL	157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,905,093	100.00%
	RESIDENTIAL RATE DESIGN	PRESENT RATES		COMPANY PROPOSED		RUCO PROPOSED	
	Residential Service - Mohave County						
7	Customer Charge per Month	$ 6.50		$ 8.00		$ 6.80	
8	Energy Charge, First 400 kWhs	$ 0.07490		$ 0.0126178		$ 0.0107306	
9	Energy Charge, All Additional kWhs	$ 0.07490		$ 0.0226180		$ 0.0192350	
10	PPFAC Charge	$ 0.018250					
11	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.0771780	
	Residential Service - Santa Cruz County						
12	Customer Charge per Month	$ 6.50		$ 8.00		$ 6.80	
13	Energy Charge, First 400 kWhs	$ 0.07930		$ 0.0126178		$ 0.0107306	
14	Energy Charge, All Additional kWhs	$ 0.07930		$ 0.0226180		$ 0.0192350	
15	PPFAC Charge	$ 0.018250					
16	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.0771780	
	RESIDENTIAL BILL COMPARISONS						
	MONTHLY ELECTRIC BILLS AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	% OF AVERAGE MONTH USAGE OF 861 kWh	ACTUAL MONTH USAGE	PRESENT MONTHLY COST	RUCO PROP'D MONTHLY COST	RUCO PROP'D MONTHLY INCREASE	RUCO PROP'D MONTHLY % INCREASE
	Residential Service - Mohave County						
17	Percentage Of Average Monthly Consumption	25.00%	215	$ 26.55	$ 25.73	$ (0.83)	-3.11%
18	Percentage Of Average Monthly Consumption	50.00%	431	$ 46.61	$ 44.92	$ (1.69)	-3.63%
19	Percentage Of Average Monthly Consumption	100.00%	861	$ 86.72	$ 86.43	$ (0.29)	-0.33%
20	Percentage Of Average Monthly Consumption	150.00%	1,292	$ 126.83	$ 127.94	$ 1.12	0.88%
21	Percentage Of Average Monthly Consumption	200.00%	1,722	$ 166.94	$ 169.46	$ 2.52	1.51%
	Residential Service - Santa Cruz County						
22	Percentage Of Average Monthly Consumption	25.00%	215	$ 27.50	$ 25.73	$ (1.77)	-6.44%
23	Percentage Of Average Monthly Consumption	50.00%	431	$ 48.50	$ 44.92	$ (3.59)	-7.40%
24	Percentage Of Average Monthly Consumption	100.00%	861	$ 90.51	$ 86.43	$ (4.08)	-4.51%
25	Percentage Of Average Monthly Consumption	150.00%	1,292	$ 132.51	$ 127.94	$ (4.57)	-3.45%
26	Percentage Of Average Monthly Consumption	200.00%	1,722	$ 174.51	$ 169.46	$ (5.06)	-2.90%

EXHIBIT
RUCO-7
Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

SURREBUTTAL TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

August 24, 2007

SURREBUTTAL TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name for the record.

A. My name is Rodney Lane Moore.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on June 28, 2007 and additional direct testimony regarding rate design on July 12, 2007.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments pertaining to adjustments I sponsored in my direct testimony.

SUMMARY OF ADJUSTMENTS

Q. What areas will you address in your surrebuttal testimony?

A. My surrebuttal testimony will address the following RUCO proposed adjustments:

Rate Base:

Adjustment No. 2 – Test-Year Accumulated Depreciation.

Operating Income:

Adjustment No. 2 – Pension and Benefits;

Adjustment No. 3 – Worker's Compensation;

Adjustment No. 4 – Incentive Compensation;

Adjustment No. 5 – Rate Case Expense;

Adjustment No. 8 – Postage Expense;

Adjustment No. 13 – Test-Year Depreciation Expense;

Adjustment No. 15 – Property Tax;
Adjustment No. 16 – SERP;
Adjustment No. 17 – Unnecessary Expenses;
Adjustment No. 18 – Maintenance of Overhead Lines;
Adjustment No. 19 – Customer Service Cost Allocation;
Adjustment No. 20 – Non-Recurring/Atypical Expenses;
Adjustment No. 22 – CARES Revenue;
Adjustment No. 23 – Membership Dues Expense;
Adjustment No. 24 – Emergency Bill Assistance Expense;
Adjustment No. 25 – Payroll Expense;
Adjustment No. 26 – Payroll Tax Expense; and
Adjustment No. 27 – Income Tax Calculation.

To support the adjustments in my surrebuttal testimony, I have revised specific direct testimony Schedules and prepared Surrebuttal Schedules numbered SURR RLM-1 though SURR RLM-4, SURR RLM-7, SURR RLM-8, SURR RLM-10, SURR RLM-11, and SURR RLM-15 through SURR RLM-17, which are filed concurrently in my surrebuttal testimony.

These Schedules quantify the adjustments recommended in RUCO's surrebuttal testimonies and consist of revisions to:

1. Customer Assistance Residential Energy Support ("CARES") Revenues to accept the Company's adjustment;
2. Worker's Compensation to accept the Company's adjustment;
3. Fleet Fuel Expenses to accept the Company's adjustment;
4. Membership Dues Expenses to accept the Company's adjustment;
5. Emergency Bill Assistance Expense to accept the Company's adjustment;

6. Depreciation and Amortization Expense to accept the Company's adjustment;
7. Property Tax Expense to accept Company's assessment ratio;
8. Income Tax Expense to reflect changes in the operating expenses associated with the surrebuttal adjustments;
9. Rate Design, Proof of Recommended Revenue and Typical Bill Analysis to reflect changes in the operating expenses associated with the surrebuttal adjustments; and

RATE BASE

RUCO Rate Base Adjustment No. 2 – Test-Year Accumulated Depreciation

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the test-year accumulated depreciation?

A. No. Despite the Company's extensive rhetoric in its rebuttal testimony about mid-year convention, salvage and removal costs, and group method depreciation the fact is the Company cannot substantiate the level of accumulated depreciation for December 31, 2003 as filed in this rate case.

However, the Company has provided a clear, concise spreadsheet in response to repetitive requests from RUCO to substantiate the level of gross plant and accumulated depreciation as of the acquisition date of August 11, 2003. Subsequently, the Company's workpapers also accurately state the level of gross plant as of December 31, 2003. Since the Company recorded no plant additions or retirements between August

11 and December 31, 2003, the calculation of the appropriate increase in accumulated depreciation over these 142 days associated with the Company's stated level of gross plant is a simple calculation of increasing the Company's stated level of accumulated depreciation as of August 11, 2003 by the sum of multiplying each plant account level by the Company's designated depreciation rate for each plant account and apportioning the total by 142/365 to recognize the partial year of accrual.

However, the Company strayed from this simple but recognized ratemaking procedure and understated the accumulated depreciation balance as of December 31, 2003 by $1,764,719.

RUCO's total calculation of accumulated depreciation through to the end of the test year adds an additional $503,393 to the Company's filed level of accumulated depreciation.

Moreover, the Company's rebuttal testimony discusses a 2005 correction to increase the accumulated depreciation balance by approximately $2 million in an attempt to provide the reconciliation for RUCO's adjustment. However, the Company's correction fails to address or even begin to substantiate the December 31, 2003 understatement. The Company's 2005 audited financial statement on page 8 shows this correction as only $0.5 million and since the correction was recorded in 2005 it is already embedded in UNS' test-year level of accumulated depreciation; therefore, the explanation also fails to explain RUCO's overall adjustment to increase test-year accumulated depreciation by $2.2 million.

In conclusion, the Company is unable to substantiate the December 31, 2003 accumulated depreciation balance, which is understated by $1,764,719. This shortfall becomes an integral component of the Company's test-year recorded level of accumulated depreciation and, despite all UNS' endeavors to explain it away, still represents the majority of RUCO's adjustment.

Therefore, as shown on SURR RLM-4, column (C) and supporting Schedule RLM-5, my proposed adjustment increases the test-year accumulated depreciation by $2,295,112 ($1,764,719 + $503,393 = $2,295,112).

OPERATING INCOME

Operating Income Adjustment No. 2 – Pension and Benefits

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the pension and benefits expenses?

A. No, I removed these costs from operating expenses for the reasons outlined in my direct testimony. My adjustment reflects the information provided by the Company in its response to Staff data request 3.81. UNS quantifies the test-year expenses identified as gifts, awards, employee dinners, picnics and social events. RUCO removed these charges from operating expenses because it considers these benefits an inappropriate financial burden on ratepayers. Whereas, the Company insists on including them in the test-year operating expenses because as it states these are normal and recurring business expenses.

Therefore, as shown on Schedule SURR RLM-8, column (C), I reversed the Company's benefit expenses as listed on UNS response to Staff data request 3.81 and decreased test-year operating expenses by $11,612.

<u>Operating Income Adjustment No. 3 – Worker's Compensation</u>

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment on worker's compensation?

A. Yes, the Company has revised its adjustment. RUCO considers the Company's position to be reasonable and in the spirit of compromise RUCO will agree with the Company and accept its rebuttal adjustment.

Therefore, as shown on Schedule SURR RLM-8, column (D), I revised the worker's compensation expense to reflect the Company's adjustment and decreased test-year operating expenses by $79,978.

Operating Income Adjustment No. 4 – Incentive Compensation

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment on incentive compensation?

A. No, for the reasons outlined in my direct testimony, the Company has failed to justify why the ratepayers should be burdened with the additional costs of an incentive program that provides no direct ratepayer benefit.

RUCO's reasons for denying the pass through to the ratepayers of the costs associated with the 2005 Special Recognition Award are:

1. Despite the considerable effort the Company takes in rebuttal to explain the ultimate benefits of its Performance Enhancement Plan ("PEP"), in reality Unisource Energy did not meet its 2005 financial performance goal and therefore the PEP program was not initiated in the test year;
2. RUCO is very reluctant to abandon the Historical Test-Year principle that avoids mismatches in the ratemaking elements. Therefore, RUCO dismisses the Company's proposal to average the 2005 Special Recognition Award and the 2004 PEP program;
3. The Company promotes the PEP program as a valuable management tool to promote additional cost savings and motivate individual employees and encourage groups of employees to work together to impact specific goals. However, over 70 percent of the workforce does not participate in this program; and

4. The Company also touts the PEP program as an employee program that reduces costs, promotes safety, increases customer service and increases the financial soundness of the Company. However, even if these efforts had been successful enough in 2005 to trigger the PEP program, 70 percent of employees sufficiently motivated to impact the actualization of these corporate goals received no compensation from the PEP program or any other arbitrary special award.

If the Company is reasonably confident it can attain its financial performance goal, operational cost containment target and customer service objectives despite the fact that the incentive compensation program incents less than one-third of the workforce, the necessity to embed such expenditures in rates is highly suspect.

Therefore, as shown on Schedule SURR RLM-8, column (E), I reversed the incentive compensation expense to reflect the Company's adjustment. The Company's adjustment was derived from a two-year average calculation of the incentive compensation; thus I decreased test-year operating expenses by $106,567.

Operating Income Adjustment No. 5 – Rate Case Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to rate case expenses?

A. No, for the reasons outlined in my direct testimony, the Company has budgeted $600,000 for rate case expenses. RUCO has a concern over the reasonableness of such a large financial burden to the ratepayers from this requested adjustment.

In comparison, RUCO recommended $251,000 as the appropriate level of rate case expense in UNS's recently filed Gas Division rate case; Docket No. G-04204A-06-0463.

Pending the Commission's approval or rejection of RUCO's recommended rate case expense for the UNS Gas Division, RUCO believes the instant case warrants the equivalent level of rate case expense because of the similarities in Company witnesses, testimonies and schedules.

This adjustment reduces annual rate case expense from the Company's proposed level of $200,000 ($600,000 / 3 years) to RUCO's recommended level of $83,667 ($251,000 / 3 years).

Therefore, as shown on Schedule SURR RLM-8, Column (F), this adjustment decreased test-year expenses by $116,333.

Operating Income Adjustment No. 8 – Postage Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to postage expenses?

A. No. RUCO maintains its strict adherence to the historical test-year principle and disagrees with the Company's proposed proforma adjustment, which averages the postage expenses for the 2.5 years from January 2004 through June 2006. The Company bases its adjustment on the belief the cost per customer bill fluctuates fairly significantly from month to month. However, no documentation was presented to support this premise.

Therefore, as shown on Schedule SURR RLM-8, column (I) and supporting Schedule RLM-9, my adjustment decreases adjusted test-year expenses by $37,956.

Operating Income Adjustment No. 13 – Depreciation Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to test-year depreciation expenses?

A. Yes, RUCO agrees with the Company to accept Staff's adjustment to reflect a portion of the transportation depreciation charged to capital accounts.

Therefore, as shown on Schedule SURR RLM-8, column (N) and supporting Schedule SURR RLM-10 (see line 37 for the removal of the capitalized expense), my adjustment decreases adjusted test-year expenses by $258,675.

Operating Income Adjustment No. 15 – Property Tax Computation

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to test-year property tax expenses?

A. Yes. RUCO will accept the Company's revised assessment ratio of 23.5 percent.

However, the level of RUCO's recommended test-year property tax expenses is directly related to RUCO's recommended value of test-year gross plant in service. RUCO's recommended value of test-year gross plant in service is directly affected by RUCO's adjustment to accumulated depreciation as was discussed previously in Rate Base Adjustment No. 2.

Therefore, as shown on Schedule SURR RLM-8, column (P) and supporting Schedule SURR RLM-11, my adjustment decreases adjusted test-year expenses by $356,711.

Operating Income Adjustment No. 16 – SERP

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the SERP?

A. No, RUCO's position is unchanged – the ratepayers should not be responsible for paying the cost of supplemental benefits to a small select group of high-ranking officers of the Company.

However, RUCO did allow the full costs of the Officer's Long Term Incentive Program and Stock Based Compensation to be included in test-year expenses.

The ratepayers are already burdened with the cost of adequately compensating this small select group of high-ranking officers for their work and who are provided with a wide array of benefits including a medical plan, dental plan, vision coverage, employee life insurance, supplemental life insurance, dependent life insurance, accidental death and dismemberment, business travel accident insurance, personal accident insurance, short and long term disability, health and dependent care spending accounts, pension, 401(k), incentive pay, vacation pay, holiday pay and sick time. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

It seems disingenuous in the present climate of spiraling utility costs to request that the ratepayers be burdened with the cost of this elite retirement plan for an exclusive group of employees who are already receiving lucrative salaries and benefits.

Therefore, as shown on Schedule RLM-8, column (Q), this adjustment decreased test-year expenses by $83,506.

<u>Operating Income Adjustment No. 17 –Inappropriate and/or Unnecessary Expenses</u>

Q. Has the Company accepted your adjustment to miscellaneous expenses?

A. No. RUCO maintains certain categories of expenses should not be the financial burden of the ratepayers. For example:

1. Liquor, Coffee, Water, Bagels, Donuts, Submarine sandwiches, etc.
2. Flowers, Sympathy Cards, Gift Certificates, Photographs, etc.
3. Charitable/Community/Service Club Donations, etc.
4. Recognition Events, Sports Events, Club Memberships, etc.
5. Numerous purchases at Circle K, Walgreen, Wal-Mart, Basha's, Fry's, Safeway, etc.

Nevertheless, the Company continues to maintain these items should be appropriately charged to ratepayers.

A sampling of the 336 questionable expenses submitted by RUCO includes invoices for: 1) $746.96 for a barbeque grill; 2) $608.40 for flags; 3) $8,078.22 for refreshments; 4) $1,377.50 to various Chambers of Commerce, and 5) $1,126.25 for chartered bus tours.

The burden of proof is on the Company to substantiate the appropriateness of the journal entries identified. The Company has failed to meet its burden and show why these costs are necessary for service.

Therefore, as shown on Schedule SURR RLM-8, column (R) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $73,620.

Operating Income Adjustment No. 18 – Maintenance of Overhead Lines

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the maintenance of overhead line expenses?

A. No. The Company's rebuttal testimony is confusing since the issue of their response to RUCO's data request 2.12 as being incomplete or knowingly inaccurate was not disclosed until now. Moreover, the 2003 maintenance of overhead line expense as filed on the 2003 FERC Form 1 reports a value of $334,755 (identical to the Company's data request response) with no footnote notation to indicate this is a partial-year expense. Without adequate documentation to overturn the data filed on the FERC Form 1, RUCO continues to rely on the evidence at hand to justify its original adjustment.

Therefore, as shown on Schedule SURR RLM-8, column (S) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $267,678.

Operating Income Adjustment No. 19 – Customer Service Cost Allocations

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the corporate allocated costs for the customer service call centers?

A. No. The Company takes considerable effort in rebuttal to explain the perceived improvements in customer service attributable to the increase in the costs associated with consolidating the interaction with its customers. However in reality, there is evidence that the customer-base has not experienced quality enhancement with the Company's transition to a consolidated call center. Therefore, RUCO maintains that with no increase in the level of customer satisfaction related to Unisource Energy's decision to integrate similar job functions among its affiliates, the UNS ratepayers should not be burdened with increased expenditures until such time as statistical information proves the costs provide a beneficial impact to UNS ratepayers.

Therefore, as shown on Schedule SURR RLM-8, column (T) and supporting Schedule RLM-14, this adjustment decreased test-year expenses by $66,797.

Operating Income Adjustment No. 20 – Non-Recurring/Atypical Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to non-recurring/atypical expenses?

A. No. This adjustment is based on background information I obtained during the discovery period in UNS's recently filed Gas Division rate case; Docket No. G-04204A-06-0463. Specifically, I had discussions with Company witness Mr. Gary Smith. During a particular conversation I expressly asked for clarification of the entries noted as "M.A.R.C. Training (Union Training)". Mr. Smith indicated this training was a one-time only instructional session to acquaint Company personnel with working in a unionized environment. Based on that conversation with Mr. Smith, I selectively excluded only expenses denoted "M.A.R.C. Training (Union Training)" from data provided. Therefore, I continue to recommend disallowance, as this is not a recurring or typical test-year expense and is not appropriate for inclusion as a rate case operating expense.

Therefore, as shown on Schedule SURR RLM-8, column (U) this adjustment decreased test-year expenses by $14,251.

Operating Income Adjustment No. 22 – CARES Revenues

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its position on CARES revenue?

A. Yes, to reduce outstanding issues in this proceeding and because of the nominal amounts involved, RUCO will agree with the Company and accept its rebuttal adjustment.

Therefore, as shown on Schedule SURR RLM-8, column (W), I revised the CARES revenue to reflect the Company's adjustment and decreased test-year operating revenues by $3,627.

Operating Income Adjustment No. 23 – Membership Dues Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its position on membership dues expenses?

A. Yes, the Company has revised its adjustment. RUCO considers the Company's position to be reasonable and in the spirit of compromise RUCO will agree with the Company and accept its rebuttal adjustment.

Therefore, as shown on Schedule SURR RLM-8, column (X), I revised the membership dues expense to reflect the Company's adjustment and decreased test-year operating expenses by $13,759.

Operating Income Adjustment No. 24 – Emergency Bill Assistance Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its position on emergency bill assistance expenses?

A. Yes, the Company has revised its adjustment. RUCO considers the Company's position to be reasonable and in the spirit of compromise RUCO will agree with the Company and accept its rebuttal adjustment.

Therefore, as shown on Schedule SURR RLM-8, column (Y), I revised the emergency bill assistance expense to reflect the Company's adjustment and increased test-year operating expenses by $20,000.

Operating Income Adjustment No. 25 – Payroll Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its position payroll expenses?

A. No. The Company has now reached out past the end of the test year to include an additional 2007 pay raise as a historical test-year expense. The inclusion of a 2007 pay raise compounds the effects of the accepted test-year pay raise and distorts the ratemaking matching principle.

As shown on Schedule SURR RLM-8, column (Z), I accepted the level of payroll tax expense as filed by the Company and therefore there is no surrebuttal adjustment and the effect on the test-year operating expenses is zero.

Operating Income Adjustment No. 27 – Payroll Tax Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its position on payroll tax expenses?

A. No, this is a companion adjustment to the previous adjustment to the payroll expense and since RUCO did not revise that adjustment, RUCO is not revising its adjustment to the payroll tax expense.

As shown on Schedule SURR RLM-8, column (AA), I accept the level of payroll tax expense as filed by the Company and therefore there is no surrebuttal adjustment and the effect on the test-year operating expenses is zero.

Operating Income Adjustment No. 27 – Income Tax Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its method of computing income tax expenses?

A. No. The Company has a conceptual disagreement with the manner by which RUCO computes income tax expenses.

RUCO's methodology for computing income tax expenses will be explained by RUCO witness Ms. Diaz Cortez in her surrebuttal testimony.

Q. Please explain RUCO's adjustment to the income tax expense.

A. This adjustment reflects income tax expenses calculated on RUCO's surrebuttal recommended revenues and expenses.

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

Q. Have you revised your additional direct testimony Schedule to present proof of your revised surrebuttal recommended revenue?

A. Yes, I have. Proof that RUCO's direct testimony recommended rate designs would produce the revised surrebuttal recommended required revenue as illustrated, is presented on Schedule SURR RLM-16.

TYPICAL BILL ANALYSIS

Q. Have you revised your additional direct testimony Schedule to present a typical bill analysis based on your surrebuttal recommended revenue?

A. Yes, I have. A revised typical bill analysis for metered residential customers with various levels of usage is presented on Schedule SURR RLM-17.

COST OF CAPITAL

Q. Is RUCO revising its adjustments to the Company proposed cost of capital?

A. No. RUCO is not revising the adjustment to the weighted cost of capital. This position is fully explained in the surrebuttal testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

UNS Electric, Inc.
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SURREBUTTAL
TABLE OF CONTENTS TO RUCO SCHEDULES

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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 140,991,324	$ 214,613,357	$ 177,802,340	$ 128,742,285	$ 194,422,808	$ 161,582,547
2	Adjusted Operating Income (Loss)	$ 8,742,011	$ 8,742,011	$ 8,742,011	$ 10,440,368	$ 10,440,368	$ 10,440,368
3	Current Rate Of Return (Line 2 / Line 1)	6.20%	4.07%	4.92%	8.11%	5.37%	6.46%
4	Required Operating Income (Line 5 X Line 1)	$ 13,946,320	$ 13,946,320	$ 13,946,320	$ 11,166,869	$ 11,166,869	$ 11,166,869
5	Required Rate Of Return	9.89%	6.50%	7.84%	8.67%	5.74%	6.91%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 5,204,309	$ 5,204,309	$ 5,204,309	$ 726,501		$ 726,501
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 3)	1.6346	1.6346	1.6346	1.6370		1.6370
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 8,507,097	$ 8,507,097	$ 8,507,097	$ 1,189,270		$ 1,189,270
9	Adjusted Test Year Revenue			$ 158,486,890	$ 158,531,911		$ 158,531,911
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 166,993,987	$ 159,721,181		$ 159,721,181
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			5.37%	0.75%		0.75%
12	Rate Of Return On Common Equity			11.39%	9.30%		9.30%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Column (D): Schedules RLM-1, Page 2, RLM-2, RLM-7 And RLM-18
Column (E): Schedule RLM-2
Column (F): Average Of Column (D) + Column (E)

UNS Electric, Inc.
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SURREBUTTAL
FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 390,513,651	$ 612,326,062	$ 501,419,857	156.80%	$ 379,752,198	$ 595,452,086	$ 487,602,142
2	Accumulated Depreciation	(159,524,693)	(257,585,628)	(208,555,161)	161.47%	(161,819,805)	(261,291,561)	(211,555,683)
3	Net Utility Plant In Service	$ 230,988,958	$ 354,740,434	$ 292,864,696		$ 217,932,393	$ 334,160,525	$ 276,046,459
4	Citizens Acquisition Discount	$ (93,273,341)	$ (150,061,415)	$ (121,667,378)	160.88%	$ (93,273,341)	$ (150,061,415)	$ (121,667,378)
5	Accumulated Amortization	11,224,066	18,123,969	14,674,018	161.47%	11,224,066	18,123,969	14,674,018
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ (131,937,446)	$ (106,993,361)		$ (82,049,275)	$ (131,937,446)	$ (106,993,361)
7	Total Net Utility Plant	$ 148,939,683	$ 222,802,988	$ 185,871,336		$ 135,883,118	$ 202,223,079	$ 169,053,099
	Deductions:							
8	Cust. Advances For Const.	$ (8,692,444)	$ (9,559,141)	$ (9,125,793)	109.97%	$ (8,692,444)	$ (9,559,141)	$ (9,125,793)
9	Customer Deposits	(3,778,419)	(3,778,419)	(3,778,419)	100.00%	(3,778,419)	(3,778,419)	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	1,780,258	1,467,546	154.16%	382,701	589,961	486,331
11	Total Deductions	$ (11,316,030)	$ (11,557,302)	$ (11,436,666)		$ (12,088,162)	$ (12,747,599)	$ (12,417,880)
12	Allowance - Working Capital	$ 3,367,671	$ 3,367,671	$ 3,367,671	100.00%	$ 4,947,328	$ 4,947,328	$ 4,947,328
13	Regulatory Assets	$ -	$ -	$ -		$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -		$ -	$ -	$ -
15	TOTAL TEST YEAR RATE BASE	$ 140,991,324	$ 214,613,357	$ 177,802,341		$ 128,742,285	$ 194,422,808	$ 161,582,547

References:
Columns (A) (B) (C): Company Schedule B-1
Column (D): Column (B) / Column (A)
Column (E): Schedule RLM-3, Column (C)
Column (F): Column (D) X Column (E)
Column (G): Average Of Column (E) + Column (F)

UNS Electric, Inc.
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SURREBUTTAL
ORIGINAL COST RATE BASE STATEMENT

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 390,513,651	$ (10,761,453)	$ 379,752,198
2	Accumulated Depreciation	(159,524,693)	(2,295,112)	(161,819,805)
3	Net Utility Plant In Service	$ 230,988,958	$ (13,056,565)	$ 217,932,393
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ (93,273,341)
5	Accumulated Amortization	11,224,066	-	11,224,066
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ -	$ (82,049,275)
7	Total Net Utility Plant	$ 148,939,683	$ (13,056,565)	$ 135,883,118
	Deductions:			
8	Cust. Advances For Const.	$ (8,692,444)	$ -	$ (8,692,444)
9	Customer Deposits	(3,778,419)	-	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	(772,132)	382,701
11	Total Deductions	$ (11,316,030)	$ (772,132)	$ (12,088,162)
12	Allowance - Working Capital	$ 3,367,671	$ 1,579,657	$ 4,947,328
13	Regulatory Assets	$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -
15	TOTAL OCRB	$ 140,991,324	$ (12,249,039)	$ 128,742,285

References:
Column (A): - Company Schedule B-2
Column (B): - RUCO Adjustments As Per RLM-4, Columns (B) Thru (G)
Column (C): - Sum Of Columns (A) And (B)

UNS Electric, Inc.
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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) INTENTIONALLY LEFT BLANK	(C) RUCO ADJUSTMENT NO. 2	(D) RUCO ADJUSTMENT NO. 3	(E) RUCO ADJUSTMENT NO. 4	(F) RUCO ADJUSTMENT NO. 5	(G) RUCO ADJUSTMENT NO. 6	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 390,513,651	$ -	$ -	$ (10,761,453)	$ -	$ -	$ -	$ 379,752,198
2	Accumulated Depreciation	(159,524,693)	-	(2,295,112)	-	-	-	-	(161,819,805)
3	Net Utility Plant In Service	$ 230,988,958	$ -	$ (2,295,112)	$ (10,761,453)	$ -	$ -	$ -	$ 217,932,393
4	Citizens Acquisition Discount	$ (93,273,341)	$ -	$ -	$ -	$ -	$ -	$ -	$ (93,273,341)
5	Accumulated Amortization	11,224,066	-	-	-	-	-	-	11,224,066
6	Net Citizens Acq. Disc.	$ (82,049,275)	$ -	$ -	$ -	$ -	$ -	$ -	$ (82,049,275)
7	Total Net Utility Plant	$ 148,939,683	$ -	$ (2,295,112)	$ (10,761,453)	$ -	$ -	$ -	$ 135,883,118
	Deductions:								
8	Cust. Advances For Const.	$ (8,692,444)	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,692,444)
9	Customer Deposits	(3,778,419)	-	-	-	-	-	-	(3,778,419)
10	Acc. Deferred Income Taxes	1,154,833	-	-	-	(888,390)	116,258	-	382,701
11	Total Deductions	$ (11,316,030)	$ -	$ -	$ -	$ (888,390)	$ 116,258	$ -	$ (12,088,162)
12	Allowance - Working Capital	$ 3,367,671	$ -	$ -	$ -	$ -	$ -	$ 1,579,657	$ 4,947,328
13	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Regulatory Liability	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TOTAL OCRB	$ 140,991,324	$ -	$ (2,295,112)	$ (10,761,453)	$ (888,390)	$ 116,258	$ 1,579,657	$ 128,742,285

References:
- Column (A): - Company Schedule B-2
- Column (B): - Intentionally Left Blank
- Column (C): - Adjustment No. 2 RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-5, Page 6, Line 46)
- Column (D): - Adjustment No. 3 RUCO Adjustment To Remove CWIP From Test-Year Rate Base (See Testimony, MDC)
- Column (E): - Adjustment No. 4 RUCO Adjustment To Remove ADIT Related To CIAC From Test-Year Rate Base (See Testimony, MDC)
- Column (F): - Adjustment No. 5 RUCO Adjustment To Adjusted ADIT Related To A & G Capitalization From Test-Year Rate Base (See Testimony, MDC)
- Column (G): - Adjustment No. 6 Allowance For Working Capital (See MDC-2)
- Column (H): - Sum Of Columns (A) Through (G)

UNS Electric, Inc.
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Test Year Ended June 30, 2006

SURREBUTTAL
OPERATING INCOME STATEMENT

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
	Operating Revenues:					
1	Electric Retail Revenues	$ 156,651,860	$ (3,627)	$ 156,648,233	$ 1,189,270	$ 157,837,503
2	Sales for Resale	246,016	-	246,016	-	246,016
3	Other Operating Revenue	1,589,014	48,648	1,637,662	-	1,637,662
4	TOTAL OPERATING REVENUES	$ 158,486,890	$ 45,021	$ 158,531,911	$ 1,189,270	$ 159,721,181
	Operating Expenses:					
5	Purchased Power	$ 106,224,185	$ (121)	$ 106,224,064	$ -	$ 106,224,064
6	Total O & M Expense	26,423,248	(1,718,198)	24,705,050	-	24,705,050
7	Depreciation and Amortization	11,812,574	(710,647)	11,101,927	-	11,101,927
8	Taxes Other than Income Taxes	3,447,533	(607,123)	2,840,410	-	2,840,410
9	Income Taxes	1,837,339	1,382,753	3,220,092	462,769	3,682,861
10	TOTAL OPERATING EXPENSES	$ 149,744,879	$ (1,653,336)	$ 148,091,543	$ 462,769	$ 148,554,312
11	OPERATING INCOME (LOSS)	$ 8,742,011	$ 1,698,357	$ 10,440,368	$ 726,501	$ 11,166,869
				$ 13,660,461		

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Testimony, RLM And Schedule RLM-1
Column (E): Column (C) + Column (D)

UNS Electric, Inc.
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Schedule SURR RLM-8
Pages 1 & 2 of 6

SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ NO. 1 SERVICE FEES & LATE FEES TESTIMONY-MDC	(C) ADJ NO. 2 PENSION & BENEFITS TESTIMONY-RLM	(D) ADJ NO. 3 WORKER'S COMP TESTIMONY-RLM	(E) ADJ NO. 4 INCENTIVE COMP. TESTIMONY-RLM	(F) ADJ NO. 5 RATE CASE EXPENSE TESTIMONY-RLM	(G) ADJ. NO. 6 BAD DEBT EXPENSE TESTIMONY-MDC	(H) ADJ NO. 7 FLEET FUEL EXPENSE TESTIMONY-MDC	(I) ADJ NO. 8 POSTAGE EXPENSE SCH. RLM-9	(J) ADJ NO. 9 YEAR-END ACCURALS TESTIMONY-MDC
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ 156,651,860	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	447	**Sales for Resale**	$ 246,016	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ 1,099,279	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	454	Rent from Electric Property	339,735	-	-	-	-	-	-	-	-	-
5	456	Other Electric Revenues	150,000	-	-	-	-	-	-	-	-	-
6		**Total Other Operating Revenue**	$ 1,589,014	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Total Operating Revenue**	$ 158,486,890	$ 48,648	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	106,021,950	-	-	-	-	-	-	-	-	-
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	202,235	-	-	-	-	-	-	(121)	-	-
12		**Total Purchased Power**	$ 106,224,185	$ -	$ -	$ -	$ -	$ -	$ -	$ (121)	$ -	$ -
		Other Power Production										
13	546	Operation Supervision & Engineering	$ 2,264	$ -	$ -	$ -	$ -	$ -	$ -	$ (363)	$ -	$ -
14	547	Fuel	266,198	-	-	-	-	-	-	-	-	-
15	548	Generation Expenses	26,287	-	-	-	-	-	-	(57)	-	-
16	549	Miscellaneous Other Power Generation	52,481	-	-	-	-	-	-	(9)	-	-
17	551	Maintenance Supervision & Engineering	54,625	-	-	-	-	-	-	(448)	-	-
18	553	Maintenance of Generating and Electric Plant	255,461	-	-	-	-	-	-	(835)	-	-
19	554	Maintenance of Misc. Other Power Generation Plt	80,460	-	-	-	-	-	-	(443)	-	-
		Transmission Expense										
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	66,776	-	-	-	-	-	-	-	-	-
22	561.2	Load Dispatch - Monitor & Operation Transmission System	9,394	-	-	-	-	-	-	-	-	-
23	562	Station Expenses	75,228	-	-	-	-	-	-	(154)	-	-
24	563	Overhead Line Expenses	3,324	-	-	-	-	-	-	(23)	-	-
25	565	Transmission of Electricity by Others	7,009,878	-	-	-	-	-	-	-	-	-
26	566	Miscellaneous Transmission Expenses	19,495	-	-	-	-	-	-	(99)	-	-
27	567	Rents	11,657	-	-	-	-	-	-	-	-	-
28	568	Maintenance Supervision & Engineering	24	-	-	-	-	-	-	-	-	-
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	20,513	-	-	-	-	-	-	(363)	-	-
31	571	Maintenance of Overhead Lines	7,354	-	-	-	-	-	-	(19)	-	-
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	364,186	-	-	-	-	-	-	(399)	-	-
34	581	Load Dispatching	437,055	-	-	-	(799)	-	-	(2,570)	-	-
35	582	Station Expenses	72,715	-	-	-	-	-	-	(195)	-	-
36	583	Overhead Line Expenses	811,053	-	-	-	-	-	-	(1,574)	-	-
37	584	Underground Line Expenses	511,510	-	-	-	-	-	-	(3,089)	-	-
38	585	Street Lighting & Signal System Expenses	1,628	-	-	-	-	-	-	(8)	-	-
39	586	Meter Expenses	743,347	-	-	-	-	-	-	(4,662)	-	-
40	587	Customer Installations Expense	15,998	-	-	-	-	-	-	(81)	-	-
41	588	Miscellaneous Distribution Expenses	351,137	-	(108)	-	(9,375)	-	-	(2,058)	-	-
42	589	Rents	99,440	-	-	-	-	-	-	-	-	-
43	590	Maintenance Supervision & Engineering	54,430	-	-	-	-	-	-	(447)	-	-
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	472,734	-	-	-	-	-	-	(2,554)	-	-
46	593	Maintenance of Overhead Lines	1,006,308	-	-	-	(9,879)	-	-	(4,448)	-	-
47	594	Maintenance of Underground Lines	142,605	-	-	-	-	-	-	(864)	-	-
48	595	Maintenance of Line Transformers	103,968	-	-	-	-	-	-	(387)	-	-
49	596	Maintenance of Street Lighting & Signal Systems	56,424	-	-	-	-	-	-	(384)	-	-
50	597	Maintenance of Meters	123	-	-	-	-	-	-	-	-	-
51	598	Maintenance of Miscellaneous Distribution Plant	7,233	-	-	-	-	-	-	(8)	-	-
		Customer Account Expense										
52	901	Supervision	172,327	-	(26)	-	(14,699)	-	-	(1,160)	-	-
53	902	Meter Reading Expenses	730,556	-	-	-	-	-	-	(618)	-	-
54	903	Customer Records & Collection Expenses	3,834,499	-	(209)	-	(1,600)	-	-	(6,313)	(37,956)	-
55	904	Uncollectible Accounts	579,538	-	-	-	-	-	(203,038)	-	-	-
56	905	Miscellaneous Customer Accounts Expenses	29,171	-	-	-	-	-	-	(94)	-	-
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	34,001	-	-	-	-	-	-	(367)	-	-
59	909	Informational and Instructional Advertising Expenses	62,059	-	-	-	(5,850)	-	-	(350)	-	-

UNS Electric, Inc.
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Schedule SURR RLM-8
Pages 1 & 2 of 6

SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 SERVICE FEES & LATE FEES TESTIMONY-MDC	(C) ADJ. NO. 2 PENSION & BENEFITS TESTIMONY-RLM	(D) ADJ NO. 3 WORKER'S COMP TESTIMONY-RLM	(E) ADJ. NO. 4 INCENTIVE COMP TESTIMONY-RLM	(F) ADJ. NO. 5 RATE CASE EXPENSE TESTIMONY-RLM	(G) ADJ. NO 6 BAD DEBT EXPENSE TESTIMONY-MDC	(H) ADJ NO. 7 FLEET FUEL EXPENSE TESTIMONY-MDC	(I) ADJ. NO. 8 POSTAGE EXPENSE SCH. RLM-9	(J) ADJ NO. 9 YEAR-END ACCURALS TESTIMONY-MDC
60	910	Miscellaneous Customer Service & Informational Expenses	9,778	-	-	-	-	-	-	(9)	-	-
		Administrative and General Expense										
61	920	Administrative & General Salaries	770,768	-	-	-	(56,045)	-		-	-	-
62	921	Office Supplies & Expenses	535,654	-	(10,129)	-	-	-	-	(5,291)	-	-
63	922	Administrative Expenses Transferred - Credit	(158,087)	-	-	-	-	-	-	-	-	-
64	923	Outside Services Employed	3,317,593	-	-	-	-	-	-	-	-	-
65	924	Property Insurance	65,596	-	-	-	-	-	-	-	-	-
66	925	Injuries and Damages	512,417	-	-	(79,978)	-	-	-	(8)	-	-
67	926	Employee Pension & Benefits	1,172,133	-	-	-	-	-	-	-	-	(6,256)
68	928	Regulatory Commission Expenses	200,000	-	-	-	-	(115,333)	-	-	-	-
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	82,478	-	(1,139)	-	-	-	-	-	-	-
71	930.2	Miscellaneous General Expenses	1,148,557	-	-	-	-	-	-	(1,654)	-	-
72	931	Rents	74,558	-	-	-	-	-	-	-	-	-
73	935	Maintenance of General Plant	35,937	-	-	-	-	-	-	-	-	-
74		**Total Operation and Maintenance Expense**	$ 26,423,248	$ -	$ (11,612)	$ (79,978)	$ (98,247)	$ (116,333)	$ (203,038)	$ (42,404)	$ (37,956)	$ (6,256)
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ 998,011	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	403/404/406	Other Production Plant	182,444	-	-	-	-	-	-	-	-	-
77	403/404/406	Transmission Plant	1,203,457	-	-	-	-	-	-	-	-	-
78	403/404/406	Distribution Plant	9,059,006	-	-	-	-	-	-	-	-	-
79	403/404/406	General Plant	369,656	-	-	-	-	-	-	-	-	-
80		**Total Depreciation & Amortization - All**	$ 11,812,574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ 192,787	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	408	Property Tax - Transmission	327,975	-	-	-	-	-	-	-	-	-
83	408	Property Tax - Distribution	2,284,584	-	-	-	-	-	-	-	-	-
84	408	Property Tax - General	291,025	-	-	-	-	-	-	-	-	-
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	348,088	-	-	-	(8,320)	-	-	-	-	-
86	408	Medical and Dental	2,773	-	-	-	-	-	-	-	-	-
87	408	Other	301	-	-	-	-	-	-	-	-	-
88		**Total Taxes Other Than Income Taxes**	$ 3,447,533	$ -	$ -	$ -	$ (8,320)	$ -	$ -	$ -	$ -	$ -
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ 1,342,818	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	410	Deferred IT - Federal & State (debit)	10,602,572	-	-	-	-	-	-	-	-	-
91	411	Deferred IT - Federal & State (credit)	(10,108,051)	-	-	-	-	-	-	-	-	-
92		**Total Income Taxes**	$ 1,837,339	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93		**Total Operating Expense**	$ 149,744,879	$ -	$ (11,612)	$ (79,978)	$ (106,567)	$ (116,333)	$ (203,038)	$ (42,525)	$ (37,956)	$ (6,256)
94		**OPERATING INCOME**	$ 8,742,011									

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 A & G EXPENSE CAPITALIZED TESTIMONY-MDC	(L) ADJ. NO. 11 DEP/PROP TX FOR CWIP TESTIMONY-MDC	(M) ADJ. NO. 12 CORP. COSTS ALLOCATIONS TESTIMONY-MDC	(N) ADJ. NO. 13 DEP/AMORT ANNUALIZN SURR RLM-10	(O) ADJ. NO. 14 VALENCIA TURBINE FUEL TESTIMONY-MDC	(P) ADJ. NO. 15 PROPERTY TAX SURR RLM-11	(Q) ADJ. NO. 16 SERP TESTIMONY-RLM	(R) ADJ. NO. 17 INAPPROPRIATE EXPENSES SCH. RLM-12	(S) ADJ. NO. 18 O/H LINES MAINTENANCE SCH. RLM-13	(T) ADJ. NO. 19 CUST. SERVICE COST ALLOC. SCH. RLM-14
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	447	**Sales for Resale**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	-
5	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	-
6		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7		**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	-	-	-	-	-	-	-	-	-	-
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	-	-	-	-	-	-	-	-	-	-
12		**Total Purchased Power**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Other Power Production										
13	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	547	Fuel	-	-	-	-	(266,198)	-	-	-	-	-
15	548	Generation Expenses	-	-	-	-	-	-	-	-	-	-
16	549	Miscellaneous Other Power Generation	-	-	-	-	-	-	-	-	-	-
17	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
18	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	-
19	554	Maintenance of Misc. Other Power Generation Plt	-	-	-	-	-	-	-	-	-	-
		Transmission Expense										
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	-	-	-	-	-	-	-	-	-	-
22	561.2	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	-
23	562	Station Expenses	-	-	-	-	-	-	-	-	-	-
24	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
25	565	Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	-
26	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	-
27	567	Rents	-	-	-	-	-	-	-	-	-	-
28	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
31	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	-
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
34	581	Load Dispatching	-	-	-	-	-	-	-	-	-	-
35	582	Station Expenses	-	-	-	-	-	-	-	-	-	-
36	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	-
37	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	-
38	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	-
39	586	Meter Expenses	-	-	-	-	-	-	-	-	-	-
40	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	-
41	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	-	-
42	589	Rents	(54)	-	-	-	-	-	-	-	-	-
43	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	-
46	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	(267,678)	-
47	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	-
48	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	-
49	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	-
50	597	Maintenance of Meters	-	-	-	-	-	-	-	-	-	-
51	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	-
		Customer Account Expense										
52	901	Supervision	-	-	-	-	-	-	-	-	-	-
53	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	-
54	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	(45,230)
55	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	-
56	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	-
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	-	-	-	-	-	-	-	-	-	-
59	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	-

UNS Electric, Inc.
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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(K) ADJ. NO. 10 A & G EXPENSE CAPITALIZED TESTIMONY-MDC	(L) ADJ. NO. 11 DEP/PROP TX FOR CWIP TESTIMONY-MDC	(M) ADJ. NO. 12 CORP COSTS ALLOCATIONS TESTIMONY-MDC	(N) ADJ. NO. 13 DEP/AMORT ANNUALIZ'N SURR RLM-10	(O) ADJ. NO. 14 VALENCIA TURBINE FUEL TESTIMONY-MDC	(P) ADJ. NO. 15 PROPERTY TAX SURR RLM-11	(Q) ADJ. NO. 16 SERP TESTIMONY-RLM	(R) ADJ. NO. 17 INAPPROPRIATE EXPENSES SCH. RLM-12	(S) ADJ. NO. 18 O/H LINES MAINTENANCE SCH. RLM-13	(T) ADJ. NO. 19 CUST. SERVICE COST ALLOC. SCH. RLM-14
60	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	-
		Administrative and General Expense										
61	920	Administrative & General Salaries	-	-	-	-	-	-		-	-	(2,346)
62	921	Office Supplies & Expenses	(128)	-	-	-	-	-	-	(21,320)	-	(1,029)
63	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(12)
64	923	Outside Services Employed	(301,005)	-	-	-	-	-	-	(20,311)	-	(236)
65	924	Property Insurance	-	-	-	-	-	-	-	-	-	(123)
66	925	Injuries and Damages	-	-	-	-	-	-	-	-	-	(27)
67	926	Employee Pension & Benefits	-	-	-	-	-	-	(83,506)	-	-	(13,242)
68	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	-	-	-	-	-	-	-	(3,539)	-	-
71	930.2	Miscellaneous General Expenses	-	-	(10,010)	-	-	-	-	(28,451)	-	-
72	931	Rents	-	-	-	-	-	-	-	-	-	-
73	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	-
74		**Total Operation and Maintenance Expense**	$ (301,187)	$ -	$ (10,010)	$ -	$ (266,198)	$ -	$ (83,506)	$ (73,620)	$ (267,678)	$ (62,245)
		Depreciation & Amortization - All										
75	403/404/405	Intangible Plant	$ -	$ (11,823)	$ -	$ (7,822)	$ -	$ -	$ -	$ -	$ -	$ -
76	403/404/405	Other Production Plant	-	(8,839)	-	(9,640)	-	-	-	-	-	-
77	403/404/405	Transmission Plant	-	(48,805)	-	5,995	-	-	-	-	-	-
78	403/404/405	Distribution Plant	-	(363,618)	-	40,227	-	-	-	-	-	-
79	403/404/405	General Plant	-	(16,731)	-	(287,435)	-	-	-	-	-	(2,156)
80		**Total Depreciation & Amortization - All**	$ -	$ (449,816)	$ -	$ (258,675)	$ -	$ -	$ -	$ -	$ -	$ (2,156)
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ -	$ (8,134)	$ -	$ -	$ -	$ (22,958)	$ -	$ -	$ -	$ -
82	408	Property Tax - Transmission	-	(31,707)	-	-	-	(38,045)	-	-	-	-
83	408	Property Tax - Distribution	-	(181,846)	-	-	-	(261,992)	-	-	-	-
84	408	Property Tax - General	-	(18,009)	-	-	-	(33,707)	-	-	-	-
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-	-	-
86	408	Medical and Dental	-	-	-	-	-	-	-	-	-	-
87	408	Other	-	-	-	-	-	-	-	-	-	(2,397)
88		**Total Taxes Other Than Income Taxes**	$ -	$ (239,696)	$ -	$ -	$ -	$ (356,711)	$ -	$ -	$ -	$ (2,397)
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	410	Deferred IT - Federal & State (debit)	-	-	-	-	-	-	-	-	-	-
91	411	Deferred IT - Federal & State (credit)	-	-	-	-	-	-	-	-	-	-
92		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93		**Total Operating Expense**	$ (301,187)	$ (689,512)	$ (10,010)	$ (258,675)	$ (266,198)	$ (356,711)	$ (83,506)	$ (73,620)	$ (267,678)	$ (66,797)
94		**OPERATING INCOME**										

UNS Electric, Inc.
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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACCT	DESCRIPTION	(U) ADJ NO. 20 ATYPICAL EXPENSES TESTIMONY-RLM	(V) ADJ. NO. 21 OUTSIDE SERVICES - DSM TESTIMONY-MDC	(W) ADJ. NO. 22 CARES REVENUE TESTIMONY-RLM	(X) ADJ. NO. 23 MEMEBERSHIP DUES TESTIMONY-RLM	(Y) ADJ. NO. 24 EMERGENCY BILL ASISTANCE TESTIMONY-RLM	(Z) ADJ. NO. 24 PAYROLL EXPENSE TESTIMONY-RLM	(AA) ADJ. NO. 24 PAYROLL TAX EXPENSE TESTIMONY-RLM	(AB) INTENTIONALLY LEFT BLANK	(AC) ADJ. NO. 27 INCOME TAX SURR RLM-15	(AD) RUCO AS ADJUSTED
		Operating Revenue										
1	440, 442, 444	**Electric Retail Revenue**	$ -	$ -	$ (3,627)	$ -	$ -	$ -	$ -	$ -	$ -	$ 156,648,233
2	447	**Sales for Resale**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 246,016
		Other Operating Revenue										
3	451	Miscellaneous Service Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,147,927
4	454	Rent from Electric Property	-	-	-	-	-	-	-	-	-	339,735
5	456	Other Electric Revenues	-	-	-	-	-	-	-	-	-	150,000
6		**Total Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,637,662
7		**Total Operating Revenue**	$ -	$ -	$ (3,627)	$ -	$ -	$ -	$ -	$ -	$ -	$ 158,531,911
		Operating Expenses										
		Purchased Power										
8	555	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	555	Energy	-	-	-	-	-	-	-	-	-	106,021,950
10	556	System Control and Load Dispatching	-	-	-	-	-	-	-	-	-	-
11	557	Other Expenses	-	-	-	-	-	-	-	-	-	202,114
12		**Total Purchased Power**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 106,224,064
		Other Power Production										
13	546	Operation Supervision & Engineering	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,901
14	547	Fuel	-	-	-	-	-	-	-	-	-	-
15	548	Generation Expenses	-	-	-	-	-	-	-	-	-	26,229
16	549	Miscellaneous Other Power Generation	-	-	-	-	-	-	-	-	-	52,472
17	551	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	54,177
18	553	Maintenance of Generating and Electric Plant	-	-	-	-	-	-	-	-	-	254,626
19	554	Maintenance of Misc. Other Power Generation Plt	-	-	-	-	-	-	-	-	-	80,017
		Transmission Expense										-
20	560	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	-
21	561	Load Dispatching	-	-	-	-	-	-	-	-	-	66,776
22	561.2	Load Dispatch - Monitor & Operation Transmission System	-	-	-	-	-	-	-	-	-	9,394
23	562	Station Expenses	-	-	-	-	-	-	-	-	-	75,074
24	563	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	3,301
25	565	Transmission of Electricity by Others	-	-	-	-	-	-	-	-	-	7,009,878
26	566	Miscellaneous Transmission Expenses	-	-	-	-	-	-	-	-	-	19,396
27	567	Rents	-	-	-	-	-	-	-	-	-	11,857
28	568	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	24
29	569	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
30	570	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	20,150
31	571	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	7,335
32	573	Maintenance of Miscellaneous Transmission Plant	-	-	-	-	-	-	-	-	-	-
		Distribution Expense										
33	580	Operation Supervision & Engineering	-	-	-	-	-	-	-	-	-	363,787
34	581	Load Dispatching	-	-	-	-	-	-	-	-	-	433,686
35	582	Station Expenses	-	-	-	-	-	-	-	-	-	72,520
36	583	Overhead Line Expenses	-	-	-	-	-	-	-	-	-	809,479
37	584	Underground Line Expenses	-	-	-	-	-	-	-	-	-	508,421
38	585	Street Lighting & Signal System Expenses	-	-	-	-	-	-	-	-	-	1,620
39	586	Meter Expenses	-	-	-	-	-	-	-	-	-	738,686
40	587	Customer Installations Expense	-	-	-	-	-	-	-	-	-	15,917
41	588	Miscellaneous Distribution Expenses	-	-	-	-	-	-	-	-	-	339,596
42	589	Rents	-	-	-	-	-	-	-	-	-	99,386
43	590	Maintenance Supervision & Engineering	-	-	-	-	-	-	-	-	-	53,983
44	591	Maintenance of Structures	-	-	-	-	-	-	-	-	-	-
45	592	Maintenance of Station Equipment	-	-	-	-	-	-	-	-	-	470,180
46	593	Maintenance of Overhead Lines	-	-	-	-	-	-	-	-	-	724,303
47	594	Maintenance of Underground Lines	-	-	-	-	-	-	-	-	-	141,741
48	595	Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-	103,581
49	596	Maintenance of Street Lighting & Signal Systems	-	-	-	-	-	-	-	-	-	56,040
50	597	Maintenance of Meters	-	-	-	-	-	-	-	-	-	123
51	598	Maintenance of Miscellaneous Distribution Plant	-	-	-	-	-	-	-	-	-	7,225
		Customer Account Expense										
52	901	Supervision	-	-	-	-	-	-	-	-	-	156,441
53	902	Meter Reading Expenses	-	-	-	-	-	-	-	-	-	729,938
54	903	Customer Records & Collection Expenses	-	-	-	-	-	-	-	-	-	3,743,191
55	904	Uncollectible Accounts	-	-	-	-	-	-	-	-	-	376,500
56	905	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-	29,077
57	907	Supervision	-	-	-	-	-	-	-	-	-	-
58	908	Customer Assistance Expenses	-	(49,920)	-	-	20,000	-	-	-	-	3,714
59	909	Informational and Instructional Advertising Expenses	-	-	-	-	-	-	-	-	-	55,869

UNS Electric, Inc.
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Test Year Ended June 30, 2006

Schedule SURR RLM-8
Pages 5 & 6 of 6

SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	FERC ACC'T	DESCRIPTION	(U) ADJ. NO. 20 ATYPICAL EXPENSES TESTIMONY-RLM	(V) ADJ. NO. 21 OUTSIDE SERVICES - DSM TESTIMONY-MDC	(W) ADJ. NO. 22 CARES REVENUE TESTIMONY-RLM	(X) ADJ. NO. 23 MEMEBERSHIP DUES TESTIMONY-RLM	(Y) ADJ. NO. 24 EMERGENCY BILL ASSISTANCE TESTIMONY-RLM	(Z) ADJ. NO. 24 PAYROLL EXPENSE TESTIMONY-RLM	(AA) ADJ. NO. 24 PAYROLL TAX EXPENSE TESTIMONY-RLM	(AB) INTENTIONALLY LEFT BLANK	(AC) ADJ. NO. 27 INCOME TAX SURR RLM-15	(AD) RUCO AS ADJUSTED
60	910	Miscellaneous Customer Service & Informational Expenses	-	-	-	-	-	-	-	-	-	9,769
		Administrative and General Expense										
61	920	Administrative & General Salaries	-	-	-	-	-	-	-	-	-	712,377
62	921	Office Supplies & Expenses	(1,382)	-	-	-	-	-	-	-	-	496,574
63	922	Administrative Expenses Transferred - Credit	-	-	-	-	-	-	-	-	-	(158,099)
64	923	Outside Services Employed	(12,869)	-	-	-	-	-	-	-	-	2,983,173
65	924	Property Insurance	-	-	-	-	-	-	-	-	-	65,475
66	925	Injuries and Damages	-	-	-	-	-	-	-	-	-	432,404
67	926	Employee Pension & Benefits	-	-	-	-	-	-	-	-	-	1,069,129
68	928	Regulatory Commission Expenses	-	-	-	-	-	-	-	-	-	83,667
69	929	Duplicate Charges - Credit	-	-	-	-	-	-	-	-	-	-
70	930.1	General Advertising Expenses	-	-	-	-	-	-	-	-	-	77,800
71	930.2	Miscellaneous General Expenses	-	-	-	(13,759)	-	-	-	-	-	1,094,684
72	931	Rents	-	-	-	-	-	-	-	-	-	74,558
73	935	Maintenance of General Plant	-	-	-	-	-	-	-	-	-	35,937
74		**Total Operation and Maintenance Expense**	$ (14,251)	$ (49,920)	$ -	$ (13,759)	$ 20,000	$ -	$ -	$ -	$ -	$ 24,705,050
		Depreciation & Amortization - All										
75	403/404/406	Intangible Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 978,366
76	403/404/406	Other Production Plant	-	-	-	-	-	-	-	-	-	163,965
77	403/404/406	Transmission Plant	-	-	-	-	-	-	-	-	-	1,160,647
78	403/404/406	Distribution Plant	-	-	-	-	-	-	-	-	-	8,735,615
79	403/404/406	General Plant	-	-	-	-	-	-	-	-	-	63,335
80		**Total Depreciation & Amortization - All**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,101,927
		Taxes Other Than Income Taxes										
81	408	Property Tax - Other Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 161,686
82	408	Property Tax - Transmission	-	-	-	-	-	-	-	-	-	258,223
83	408	Property Tax - Distribution	-	-	-	-	-	-	-	-	-	1,840,746
84	408	Property Tax - General	-	-	-	-	-	-	-	-	-	239,309
85	408	Payroll Taxes - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-	-	339,768
86	408	Medical and Dental	-	-	-	-	-	-	-	-	-	2,773
87	408	Other	-	-	-	-	-	-	-	-	-	(2,096)
88		**Total Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,840,410
		Income Taxes										
89	409	Current Income Tax - State & Federal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,382,753	$ 2,725,571
90	410	Deferred IT - Federal & State (debit)	-	-	-	-	-	-	-	-	-	10,602,572
91	411	Deferred IT - Federal & State (credit)	-	-	-	-	-	-	-	-	-	(10,108,051)
92		**Total Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,382,753	$ 3,220,092
93		**Total Operating Expense**	$ (14,251)	$ (49,920)	$ -	$ (13,759)	$ 20,000	$ -	$ -	$ -	$ 1,382,753	$ 148,091,543
94		**OPERATING INCOME**										$ 10,440,368

UNS Electric, Inc.
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SURREBUTTAL
OPERATING INCOME ADJUSTMENT NO. 13
TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE

LINE NO.	ACCT. NO.	DESCRIPTION	(A) RUCO TOTAL PLANT AS ADJUSTED	(B) COMPANY PROP'D DEP. RATE	(C) RUCO DEPREC'N EXPENSE	(D) CO. COMPUTED NET OF CWIP DEP. EXP.	(E) DIFFERENCE
		Intangible:					
1	302	Franchises & Consents	$ 11,908	4.00%	$ 476		
2	303	Miscellaneous Intangible	10,522,654	6.59%	693,592		
3		Total Intangible Plant	$ 10,534,562		$ 694,069	$ 701,891	$ (7,822)
		Other Production					
	340	Land & Rights	$ 765,874	0.00%	$ -		
7	341	Structures & Improvements	1,141,496	2.07%	23,629		
8	342	Fuel Holders, Producers & Acc.	1,163,837	2.51%	29,212		
9	343	Prime Movers	15,413,970	2.53%	389,973		
10	344	Generators	4,850,577	2.33%	113,018		
11	345	Accessory Electric Equipment	3,106,440	2.35%	73,001		
12	346	Misc. Power Plant Equipment	910,585	2.64%	24,039		
13		Total Other Production	$ 27,352,778		$ 652,874	$ 662,514	$ (9,640)
14		Transmission :					
	350	Land & Rights	$ 957,990	0.55%	$ 5,239		
15	352	Structures & Improvements	191,668	3.13%	5,999		
	353	Station Equipment	17,749,373	3.15%	559,105		
16	354	Towers & Fixtures	521,825	5.03%	26,248		
17	355	Poles & Fixtures	12,270,355	4.48%	549,712		
18	356	Overhead Conductors & Devices	11,237,573	2.66%	298,919		
19	359	Roads & Trails	183,860	2.02%	3,714		
20		Total Transmission Plant	$ 43,112,645		$ 1,448,937	$ 1,442,942	$ 5,995
21		Distribution:			-		
22	360	Land & Rights	$ 1,117,885	0.15%	$ 1,654		
23	361	Structures & Improvements	4,079,498	2.96%	120,753		
24	362	Station Equipment	32,948,470	4.09%	1,347,592		
25	364	Poles, Towers & Fixtures	76,284,703	4.14%	3,158,187		
26	365	Overhead Conductors & Devices	49,720,736	4.13%	2,053,466		
27	366	Underground Conduit	12,601,063	3.79%	477,580		
28	367	UG Conductors & Devices	27,259,007	4.40%	1,199,396		
29	368	Line Transformers	47,499,187	4.63%	2,199,212		
30	369	Services	10,695,563	3.76%	402,553		
	370	Meters	9,796,742	3.11%	304,679		
31	373	Street Lights & Signal Systems	3,811,071	4.04%	153,967		
		Total Distribution Plant	$ 275,813,925		$ 11,419,040	$ 11,378,813	$ 40,227
32		General:					
33	389	Land & Rights	$ 57,580	0.00%	$ -		
34	390	Structures & Improvements	1,852,506	2.65%	49,091		
35	391	Office Furniture & Equipment	3,220,489	9.11%	293,529		
36	392	Transportation Equipment	10,340,406	12.96%	1,340,262		
37		Capitalized Portion Of Transportation Depreciation As Per UNS Rebuttal)			(91,446)		
38	393	Stores Equipment	122,871	3.03%	3,723		
39	394	Tools, Shop And Garage Equip.	2,442,774	3.45%	84,276		
40	395	Laboratory Equipment	1,307,729	2.50%	32,693		
41	396	Power Operated Equipment	1,209,326	6.92%	83,685		
42	397	Communication Equipment	2,262,795	4.35%	98,432		
43	398	Miscellaneous Equipment	121,811	5.56%	6,773		
44		Total General Plant	$ 22,938,287		$ 1,901,018	$ 2,188,453	$ (287,435)
45		SUB TOTALS			$ 16,115,938	$ 16,374,613	$ (258,675)
46		Annualized Amortization - Acquisition Discount			(3,781,656)	(3,781,656)	
47		Vehicle Depreciation Charged To CWIP			(897,691)	(897,691)	
48		Adjustment Difference - Booked Value To Company Computation			117,308	117,308	
49		TOTALS	$ 379,752,198		$ 11,553,899	$ 11,812,574	$ (258,675)
50		Company Test-Year Depreciation As Filed			$ 11,812,574		
51		Surrebuttal Difference			(258,675)		
52		RUCO Surrebuttal Adjustment (See RLM-8, Pages 3 & 4, Column (N))			$ (258,675)		

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SURREBUTTAL
OPERATING INCOME ADJUSTMENT NO. 15
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service (RLM-4, Column (H), Line 7)		$ 135,883,118
2	Licensed Transportation (Company Workpapers)	$ (3,834,788)	
3	Land Cost And Rights (Company Workpapers)	(1,816,844)	
4	Environmental Property (Company Workpapers)	(5,563,286)	
5	Non-Taxable WAPA Portion Of N Havasu Sub	(4,674,822)	
6	CWIP In Rate Base	(10,802,316)	
7	Net Book Value Of Generation	(17,285,854)	
8	Full Cash Value Of Generation	7,943,440	
9	Land FCV Per ADOR (Company Workpapers)	1,551,539	
10	Material And Supplies (Company Workpapers)	5,650,559	
11	COMPANY'S FULL CASH VALUE (Sum Of Lines 1 Thru 10)		$ 107,050,746
	Calculation Of The Company's Tax Liability:		
8	Assessment Ratio (Per House Bill 2779)	23.5%	
9	Assessed Value (Line 7 X Line 8)	$ 25,156,925	
10	Average Tax Rate (Company Workpapers)	9.69%	
13	PROPERTY TAX Excluding Environmental Property (Line 9 X Line 10)		$ 2,436,649
14	Environmental Property (Line 4)	$ 5,563,286	
15	Statutory FCV Adjustment (Company Workpapers)	50%	
16	Environmental Property FVC (Line14 X Line 15)	$ 2,781,643	
17	Asessment Ratio Line 8)	23.5%	
18	Taxable Value (Line 16 X Line 17)	$ 653,686	
19	Average Tax Rate (Company Workpapers)	9.69%	
20	PROPERTY TAX On Environmental Property (Line 18 X Line 19)		$ 63,315
21	PROPERTY TAX On Leased Property (Company Workpapers)		
22	COMPANY PROPERTY TAX LIABILITY (Sum Of Lines 13, 20 & 21)		$ 2,499,964
23	Total Test Year Adjusted Property Tax Expense Per Company's Filing	$ 3,096,371	
24	Property Tax Associated With CWIP	(239,696)	
25	Rounding	(8)	
26	Net Test Year Adjusted Property Tax Expense Per Company's Filing	$ 2,856,667	
27	Decrease In Property Tax Expense (Line 22 - Line 26)	$ (356,703)	

LINE NO.	Distribution Of Property Tax Adjustment	COMPANY WORKPAPERS	ALLOCATION FACTOR	RUCO ALLOCATION
28	Generation	$ 184,653	6.44%	$ (22,968)
29	Transmission	305,868	10.67%	(38,045)
30	Distribution	2,106,338	73.45%	(261,992)
31	General/Intangible	270,993	9.45%	(33,707)
32	Totals	$ 2,867,852	100.00%	$ (356,711)

LINE NO.	DESCRIPTION	(B)
33	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (Line 24) (See RLM-8, Pages 3 & 4, Column (P))	$ (356,711)

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SURREBUTTAL
OPERATING INCOME ADJUSTMENT NO. 27
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-7, Column (C), Line 11 + Line 9	$ 13,660,461
	LESS:		
2	Arizona State Tax	Line 11	(581,302)
3	Interest Expense	Note (A) Line 22	(5,318,010)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 7,761,148
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 9	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 2,638,790
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 13,660,461
	LESS:		
8	Interest Expense	Note (A) Line 22	(5,318,010)
9	State Taxable Income	Line 7 + Line 8	$ 8,342,450
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 581,302
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 2,638,790
13	State Income Tax Expense	Line 11	581,302
14	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 3,220,092
15	Total Income Tax Expense Per Company Filing (Schedule C-1)		1,837,339
16	Difference	Line 14 - Line 15	$ 1,382,753
17	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 8, Pages 5 & 6, Column (AC))	Line 16	$ 1,382,753

NOTE (A):
Interest Synchronization:

LINE NO.	DESCRIPTION	AMOUNT
18	Adjusted Rate Base (Schedule RLM-3, Column (C), Line 16)	$ 128,742,285
19	Weighted Cost Of Debt (Schedule RLM-16, Column (F), Line 1 + Line 2)	4.13%
20	Interest Expense (Line 20 X Line 21)	$ 5,318,010

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Schedule SURR RLM-16
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SURREBUTTAL
RATE DESIGN AND PROOF OF RUCO RECOMMENDED REQUIRED REVENUE

LINE NO.	DESCRIPTION	(A) RATE SCH.	(B) RUCO ADJ'D BILL DETERM'TS	(C) RUCO ADJ'D RATES AND CHARGES	(D) RUCO PROPOSED REVENUE CALCULATION	(E) RUCO PROPOSED REVENUE BY CUST. CLASS
	Residential Service	R-01				
1	Customer Charge per Month		929,088	$ 6.87	$ 6,387,428	
2	Energy Charge, First 400 kWhs		320,682,178	$ 0.01084	3,477,264	
3	Energy Charge, All Additional kWhs		481,023,266	$ 0.01944	9,349,739	
4	Base Power Supply Charge, All kWhs		801,705,444	$ 0.07718	61,874,023	
5	SUB-TOTAL RESIDENTIAL SERVICE					$ 81,088,454
	Small General Service	GS-10				
6	Customer Charge per Month		89,914	$ 10.31	$ 927,231	
7	Energy Charge, First 400 kWhs		36,412,013	$ 0.02386	868,960	
8	Energy Charge, All Additional kWhs		54,618,021	$ 0.03246	1,772,904	
9	Base Power Supply Charge, All kWhs		91,030,034	$ 0.07495	6,822,428	
10	SUB-TOTAL SMALL GENERAL SERVICE					$ 10,391,522
	Large General Service	LGS				
11	Customer Charge per Month		24,301	$ 9.54	$ 231,807	
12	Demand Charge, Per kW		1,426,880	$ 9.02336	12,875,258	
13	Energy Charge, Per kWh		491,246,281	$ 0.00644	3,164,944	
14	Base Power Supply Charge, All kWhs		491,246,281	$ 0.06636	32,600,086	
15	Total Large General Service				$ 48,872,094	
	Large General Service - TOU	LGS				
16	Customer Charge per Month		120	$ 13.75	$ 1,650	
17	Demand Charge, Per kW		11,084	$ 9.02336	100,015	
18	Energy Charge, Per kWh		2,903,715	$ 0.00644	18,708	
19	Base Power Supply Charge, All kWhs		2,903,715	$ 0.06636	192,696	
20	Total Large General Service - TOU				$ 313,069	
21	SUB-TOTAL LARGE GENERAL SERVICE					$ 49,185,163
	Large Power Service - < 69KV	LPS				
22	Customer Charge per Month		75	$ 313.67	$ 23,525	
23	Demand Charge, Per kW		81,047	$ 18.50219	1,499,547	
25	Base Power Supply Charge, All kWhs		41,382,039	$ 0.05270	2,180,999	
26	Total Large General Service - < 69KV				$ 3,704,071	
	Large Power Service - > 69KV	LPS				
27	Customer Charge per Month		69	$ 343.74721	$ 23,719	
28	Demand Charge, Per kW		288,524	$ 10.76788	3,106,792	
30	Base Power Supply Charge, All kWhs		157,244,717	$ 0.05270	8,287,426	
31	Total Large General Service - > 69KV				$ 11,417,936	
32	SUB-TOTAL LARGE POWER SERVICE					$ 15,122,008
	Interruptible Power Service	IPS				
33	Customer Charge per Month		235	$ 9.53899	$ 2,242	
34	Demand Charge, Per kW		63,585	$ 3.00779	191,250	
35	Energy Charge, Per kWh		17,598,914	$ 0.01570	276,284	
37	Base Power Supply Charge, All kWhs		17,598,914	$ 0.05491	966,374	
38	Total Interruptible Service					
39	SUB-TOTAL INTERUPTIBLE SERVICE					$ 1,436,150
	Lighting Dusk To Dawn Service - O/H Service	LTG				
40	Existing Wood Pole		39,277	$ -	$ -	
41	New 30' Wood Pole (Class 6)		8,220	$ 3.86716	31,788	
42	New 30' Metal Or Fiberglass		2,385	$ 7.75150	18,487	
	Lighting Dusk To Dawn Service - U/G Service					
43	Existing Wood Pole		686	$ 1.93358	1,326	
44	New 30' Wood Pole (Class 6)		347	$ 5.80933	2,016	
45	New 30' Metal Or Fiberglass		7,646	$ 9.68508	74,052	
46	Per Watt		7,866,778	$ 0.06231	490,163	
48	SUB-TOTAL LIGHTING DUSK TO DAWN SERVICE					$ 617,833
49	TOTAL REVENUE PER RUCO BILL DETERMINENTS					$ 157,841,130
50	CARES Revenue					(3,627)
51	Sales For Resale					246,016
52	Other Operating Revenue					1,637,662
53	TOTAL PROPOSED REVENUE					$ 159,721,181
54	Proposed Annual Revenue Requirement					$ 159,721,181
55	Difference					$ 0

SURREBUTTAL
TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)	(E)	(F)
		PRESENT REVENUE		COMPANY PROPOSED		RUCO PROPOSED	
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 81,247,060	51.48%	$ 84,232,815	51.02%	$ 81,088,454	51.37%
2	OTHER	$ 76,580,097	48.52%	$ 80,878,384	48.98%	$ 76,752,676	48.63%
3	TOTAL	$ 157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,841,130	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	7,403,038	4.69%	8,989,479	5.44%	$ 7,725,271	4.89%
5	VARIABLE REVENUE	150,424,119	95.31%	156,121,720	94.56%	$ 150,115,859	95.11%
6	TOTAL	157,827,157	100.00%	$ 165,111,199	100.00%	$ 157,841,130	100.00%
	RESIDENTIAL RATE DESIGN	PRESENT RATES		COMPANY PROPOSED		RUCO PROPOSED	
	Residential Service - Mohave County						
7	Customer Charge per Month	$ 6.50		$ 8.00		$ 6.87	
8	Energy Charge, First 400 kWhs	$ 0.07490		$ 0.0126178		$ 0.01084	
9	Energy Charge, All Additional kWhs	$ 0.07490		$ 0.0226180		$ 0.01944	
10	PPFAC Charge	$ 0.018250					
11	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.0771780	
	Residential Service - Santa Cruz County						
12	Customer Charge per Month	$ 6.50		$ 8.00		$ 6.87	
13	Energy Charge, First 400 kWhs	$ 0.07930		$ 0.0126178		$ 0.0108433	
14	Energy Charge, All Additional kWhs	$ 0.07930		$ 0.0226180		$ 0.0194372	
15	PPFAC Charge	$ 0.018250					
16	Residential Service Base Power Supply Charge, All kWhs			$ 0.0771780		$ 0.0771780	

LINE NO.	**RESIDENTIAL BILL COMPARISONS** MONTHLY ELECTRIC BILLS AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	% OF AVERAGE MONTH USAGE OF 861 kWh	ACTUAL MONTH USAGE	PRESENT MONTHLY COST	RUCO PROP'D MONTHLY COST	RUCO PROP'D MONTHLY INCREASE	RUCO PROP'D MONTHLY % INCREASE
	Residential Service - Mohave County						
17	Percentage Of Average Monthly Consumption	25.00%	215	$ 26.55	$ 25.83	$ (0.73)	-2.75%
18	Percentage Of Average Monthly Consumption	50.00%	431	$ 46.61	$ 45.04	$ (1.57)	-3.37%
19	Percentage Of Average Monthly Consumption	100.00%	861	$ 86.72	$ 86.64	$ (0.08)	-0.09%
20	Percentage Of Average Monthly Consumption	150.00%	1,292	$ 126.83	$ 128.24	$ 1.41	1.11%
21	Percentage Of Average Monthly Consumption	200.00%	1,722	$ 166.94	$ 169.84	$ 2.91	1.74%
	Residential Service - Santa Cruz County						
22	Percentage Of Average Monthly Consumption	25.00%	215	$ 27.50	$ 25.83	$ (1.68)	-6.10%
23	Percentage Of Average Monthly Consumption	50.00%	431	$ 48.50	$ 45.04	$ (3.47)	-7.14%
24	Percentage Of Average Monthly Consumption	100.00%	861	$ 90.51	$ 86.64	$ (3.87)	-4.27%
25	Percentage Of Average Monthly Consumption	150.00%	1,292	$ 132.51	$ 128.24	$ (4.27)	-3.22%
26	Percentage Of Average Monthly Consumption	200.00%	1,722	$ 174.51	$ 169.84	$ (4.67)	-2.68%

EXHIBIT

RUCO-8

Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 28, 2007

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss certain issues pertaining to operating income, rate base, and to present my recommendations on these issues. RUCO witness Rodney L. Moore also presents recommendations on these same ratemaking elements, as well as sponsors RUCO's overall revenue requirement recommendation. RUCO witness William A. Rigsby presents recommendations regarding cost of capital.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. Procedures performed included the issuance of seven sets of data requests, review of other parties' data requests, conversations with Company personnel, and the review of prior ACC Decisions pertaining to this Company.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-4.

Q. Please summarize the issues and recommendations you address in your testimony.

A. My testimony addresses the following issues:

GENERATATION

* Capacity – Black Mountain Generating Station
* Purchased Power and Fuel Adjustment Clause (PPFAC)

RATE BASE

* Construction Work in Progress
* Accumulated Deferred Income Taxes
* Working Capital

OPERATING INCOME

* Miscellaneous Service Fees
* Bad Debt Expense
* Year-end Accruals
* Administrative and General Expense Capitalization
* Construction Work in Progress Property Taxes
* Corporate Cost Allocations
* Valencia Turbine Fuel

OTHER ISSUES

* Demand-side Management (DSM)

GENERATION

Black Mountain Generating Station

Q. What is UNS Electric's current source of generation?

A. Currently, UNS Electric obtains its power through a full requirements Power Supply Agreement (PSA) with Pinnacle West Capital Corporation (PWCC). This contract will expire on June 1, 2008. UNS Electric also owns 65 MW of generation capacity in Santa Cruz County that is used for reliability must run circumstances.

Q. How does UNS plan to supply its customers with power once the PWCC contract expires?

A. According to the Company, it has developed a Procurement Plan that provides for a mix of market power purchases, resource acquisitions, and supply contracts to provide the capacity, energy, and reserves necessary to serve its customers. UNS Electric has already secured 100 MW of power supply contracts that it procured pursuant to a Request for Proposal (RFP) process. These contracts will become effective June 1, 2008 when the PWCC contract expires. The Company also plans to purchase a 90 MW generating station, the Black Mountain Generating Station, which its affiliate UniSource Energy Development Company (UEDC) plans to build.

Q. What changes is the Company requesting in its base rates and PPFAC mechanism to accommodate the changes in its power supply that will take place when the PWCC contract expires in June 2008?

A. The Company is proposing a "stepped in" rate increase that would take place in two phases. Step 1 would reflect any change in rates necessitated by the adjusted test year ended June 30, 2006 and Step 2 would incorporate the investment and expenses associated with the planned purchase of the Black Mountain Generating Station in June 2008. The Company proposes the following modifications to the PPFAC:

1) Change the current PPFAC, which is a fixed rate, to an automatically adjusting rate based on a twelve-month rolling average;

2) Confirmation that the PPFAC will include all costs in FERC accounts 501, 547, 555, and 565, as well as the cost of credit support associated with purchased power procurement and hedging;

3) Authorization to accrue carrying costs on the bank balance at a rate equal to LIBOR plus 1%; and

4) Change the PPFAC Bank Threshold to $10 million for both under- or over- collected bank balances and add a defined recovery period.

Q. Does RUCO agree with these proposed changes?

A. No, not in their entirety.

Q. Please discuss RUCO's position on the proposed stepped-in rate increase for the Black Mountain Generating Station.

A. RUCO opposes this proposal. The proposal is contrary to nearly every ratemaking principle to which Arizona adheres. It violates the known and measurable principle, the matching principle, the historical test year principle, and the used and useful principle. The proposal also would circumvent the higher level of scrutiny typically afforded related party transactions and, in large part, pre-determine prudency.

Q. Please explain.

A. The level of investment as well as the operating costs of the Black Mountain Generating Station are not known and measurable at this juncture since construction, let alone operation of the plant, has not even begun. Likewise, the proposal by definition does not provide a proper matching of costs because both the incremental costs as well as the cost savings resulting from the transaction are unknown. The investment is projected to take place more than two years outside of the test year and thus violates the historical test year principle. Neither is the proposed plant used and useful since it has not even been built yet. Further, the proposed transaction is a related party transaction which requires a high level of scrutiny to insure there are no related party abuses, and that it is equivalent to a transaction that would happen at an arm's length. Such scrutiny is not possible at this time since the plant is not built, the costs are unknown, and the transaction has not occurred. Lastly, approval of the Company's proposed Step 2 rates would result in piecemeal ratemaking, as it would consider only the incremental cost changes resulting from the acquisition of the generating station, but not changes in any of the other ratemaking elements.

Q. What does RUCO recommend regarding the issue of the generating station and stepped-in rates?

A. RUCO recommends that the Commission deny the Company's request for stepped-in rates. As discussed above, this proposal is contrary to nearly every ratemaking principle. Probably the worst aspect of this proposal, however, is that it would require the Commission to grant rate base approval of an asset prior even to its existence. The very notion of this is unprecedented. Further, RUCO has concerns that premature rate base approval of this proposed asset might affect any future determination of prudency.

Q. How does RUCO propose that the Company recover its generation costs once the PWCC contract expires in the absence of stepped-in rates?

A. RUCO recommends the current PPFAC be modified in this proceeding so that it is capable of giving the Company an opportunity to recover its power costs, while still protecting ratepayers from large fluctuations in power costs. RUCO recognizes that at some point in time if and when the Black Mountain Generating Station actually exists, and its costs are known and measurable, that acquisition of this asset may be a good investment. However, that determination is impossible at this juncture. In the interim, once the proposed plant enters service, the Company can enter into a short term PPA with its affiliate UEDC to acquire the output of the plant and then file a request for acquisition and rate base recognition of this asset in a rate case, thus avoiding the violation of all the ratemaking principles just discussed.

Purchased Power and Fuel Adjustor Clause (PPFAC)

Q. Do you agree with the Company that some modifications to its existing PPFAC are necessary to accommodate the expiration of the PWCC contract in June 2008?

A. Yes. The current PPFAC is a non-adjusting mechanism since the existing PWCC power contract carries a fixed rate. However, once that contract expires, UNS Electric's power costs will no longer be fixed and the PPFAC will require more flexibility in order for the Company to remain whole.

Q. Do you agree with the PPFAC that the Company is proposing?

A. No, not in its entirety. While it is necessary that the PPFAC be modified so it can adjust to changes in prices, ratepayers at the same time need to be protected from wild market swings, any potential related-party abuses, and poor management decisions. Thus, the flexibility of the new PPFAC needs to be tempered with adequate protections for ratepayers.

Q. What aspects of the Company's proposed PPFAC do you agree with?

A. RUCO agrees with the following aspects of the Company's proposed PPFAC:

1) The new PPFAC will be self-adjusting based on a twelve-month rolling average of fuel and purchased power costs;

2) PPFAC will include costs from FERC accounts 501, 547, 555, 565;

3) The bank threshold will be set at $10 million for both under- and over-recoveries;

4) Carrying costs on the bank balance will be accrued at LIBOR plus 1%.

Q. What aspects of the Company's proposed PPFAC do you disagree with?

A. RUCO disagrees with the following aspects of the Company-proposed PPFAC:

1) Recovery of Letter of Credit Fees (LOC) through the PPFAC;

2) Automatic instatement of a surcharge or surcredit when the bank balance exceeds the $10 million threshold;

3) No cap on the amount the PPFAC can automatically adjust; and

4) Lack of incentive in the structure of the PPFAC for the Company to mitigate costs.

Q. Please discuss the first of the shortcomings of the Company's proposed PPFAC.

A. The purpose of a PPFAC is to allow the utility to recover fluctuations in its cost of fuel and purchase power. Historically, adjustors of this type have been authorized because fuel and purchased power costs represent a high percentage of a utility's total operating costs, these costs tend to be volatile in nature, and are, in part, beyond the control of management. LOC fees however do not meet any of the above-cited reasons for automatic adjustment and, as such, should be included in the Company's other operating expenses, and not flowed through the PPFAC.

Q. Please discuss the second shortcoming of the Company's proposed PPFAC.

A. The Company's proposed PPFAC would allow the Company to automatically, with no Commission oversight, begin recovering the PPFAC bank balance once it exceeds the $10 million threshold. RUCO believes this provision circumvents the Commission's authority to regulate the timing and manner in which excess bank balances are recovered from ratepayers. It is important that the Commission retain its ability to set the terms of excess PPFAC bank balances on a case-by-case basis in order to protect the public.

Q. Please discuss the third shortcoming of the Company's proposed PPFAC.

A. The Company proposed PPFAC has no cap limiting the amount by which adjustor can change over an annual period. This creates the potential for rate shock in a period of wildly escalating fuel and purchased power costs. The lack of a cap also exposes the Company's ratepayers to market risks, for which the Company is already compensated through its return on equity. While the use of a twelve-month rolling average somewhat tempers the magnitude of annual changes in the PPFAC rate, RUCO does not believe it provides adequate protections to ratepayers from unpredictable markets.

Q. Has the Commission set caps on other utilities' fuel and purchased power adjustors?

A. Yes. APS has a 4 mil annual cap on its Power Supply Adjustor (PSA). The Commission voted for renewal of this extra protection in APS' recent rate case. Because APS owns power plants to serve most of its load, APS' exposure to fluctuating costs is primarily related to the fuel its generating plants use. The Commission still deemed the extra protection of a cap warranted. UNS Electric will be exposed to potentially greater fluctuations than APS, given that it must secure its power primarily in the market.

Q. Please discuss the fourth shortcoming of the Company's proposed PPFAC.

A. The proposed PPFAC provides in large part a blank check for the Company to recover its fuel and purchased power cost, whatever these costs should be. The automatic flow-though characteristics of the proposed PPFAC provide no incentive for the Company to control and contain its fuel and purchased power costs. This is particularly disturbing considering that the Company, at least in the short run, will be exposed nearly 100% to the purchased power markets. It is even more disturbing considering the probability of related party transactions for the procurement of power.

Q. What are RUCO's recommendations to remedy the four shortcomings in the Company's proposed PPFAC?

A. RUCO recommends the following modifications to the Company's proposed PPFAC:

1) Deny recovery of LOC fees in the PPFAC and limit PPFAC eligible costs to FERC accounts 501, 547, 555, and 565;

2) Deny automatic adjustment of the PPFAC when the $10 million threshold is reached, and require the Company to instead file an application for recovery/refund of the excess balance for Commission consideration;

3) Set a cap of 6 mils per year on the amount the PPFAC can increase. Amounts over the cap would accrue to the bank balance; and

4) Require a 90/10 sharing between ratepayers and shareholders of any fuel and purchase power costs that exceed the base cost of fuel and purchased power.

Q. With these modifications, does RUCO believe that the dual objective of allowing the Company an opportunity to recover its prudently incurred fuel and purchased power costs and protecting the ratepayer from wide rate swings and poor management decisions is met?

A. Yes. The cap will temper wide rate swings in the event that the twelve-month rolling average by itself cannot. The cap provides an extra protection that I believe is absolutely imperative given the fact that, at least in the short run, the Company will be subject primarily to the market for its power supply. Further, requiring Commission approval of recovery of any accrued bank balances that exceed the $10 million threshold, rather than automatic flow through, allows the Commission discretion in determining the terms and amounts of recovery given the then-current circumstances. Finally, the 90/10 sharing mechanism provides the Company with real motivation to control its power supply costs and make wise and prudent choices in procuring power. These safeguards are imperative for an electric distribution company that, at least in the short run, will be virtually totally dependent on purchased power.

RATE BASE

Rate Base Adjustment #3 – Construction Work in Progress (CWIP)

Q. Is UNS Gas requesting the inclusion of its test year-end CWIP balance in rate base?

A. Yes. The Company claims that this extraordinary treatment of CWIP is warranted for it to maintain its financial integrity, to fund its rapid growth, to mitigate regulatory lag, to make up for its large negative acquisition adjustment, and to prolong the period between rate cases.

Q. Is this the accepted ratemaking treatment for CWIP?

A. No. Utility regulation routinely excludes CWIP from rate base because it does not meet the used and useful ratemaking standard, which requires that assets actually be in service and providing a benefit to ratepayers before their inclusion in rates. Utility accounting already allows the accrual of interest, in the form of an Allowance for Funds Used During Construction (AFUDC), on the CWIP balances. These interest accruals are ultimately recovered over the life of the asset once it enters service through depreciation expense. Thus, rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery.

Q. Are you aware of any instances where utility commissions have made an exception to standard ratemaking treatment and included CWIP in rate base?

A. Yes, but only as result of extraordinary circumstances. During the 1970's and 1980's many utility commissions made an exception and allowed CWIP in rate base. In most cases the exception was made due to the drain on cash flow caused by construction of nuclear plants. Due to the large outlays of cash required to build a nuclear plant coupled with the very long lead time before such plants enter service, many utilities became unable to service their debt due to lack of cash flows. The inclusion of CWIP was considered an emergency measure as well as a temporary measure. It historically has not been a routine ratemaking mechanism. In fact, Arizona Public Service Company was recently denied a similar request for the recognition of CWIP in rate base.[1]

Q. Do the reasons cited by the Company that warrant rate base treatment of CWIP meet the "extraordinary circumstance" standard just discussed?

A. No. First, the Company's argument that CWIP in rate base is necessary to maintain financial integrity is without merit. Other than in extraordinary circumstances, this Commission has never allowed CWIP in rate base and Arizona utilities have not lost their financial integrity as a result. Likewise, the Company's growth argument is without merit as growth has a positive

[1] Decision No. ___, Docket Nos. E-01345A-05-0816, E-01345A-05-0826, AND E-01345A-05-0827.

effect on the Company, generating more revenue and cash flow. Regulatory lag always has been a characteristic of rate of return regulation. It does not all of a sudden create a need to put CWIP in rate base. Regulatory lag is a two way street that works both for and against the Company. Types of regulatory lag that benefit the Company are plant retirements, accumulated depreciation, and expired amortizations. In all these instances the Company continues to earn a return on and recovery of assets that have already been recovered. Thus, the notion that we need to mitigate the regulatory lag that does not favor the Company, such as the Company suggests in its CWIP in rate base argument, yet continue to allow the effects of regulation that do benefit the Company, is clearly biased. The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit. The Company currently has no CWIP in rate base and even so it has been ten years since its last rate case in 1995. In fact, no large Arizona utilities that I am aware of have CWIP in rate base, yet these utilities are not filing back-to-back rate cases. Further, in my experience the Commission has favored, rather than disapproved of, utilities coming in for regular rate reviews. Finally, the Company's argument that the large negative acquisition it agreed to when it acquired Citizens gas properties now justifies the inclusion of CWIP in rate base, is disingenuous at best.

Q. Why do you say this argument is disingenuous at best?

A. At the time of the settlement agreement, the Company touted the negative acquisition as an attractive feature of the agreement that would provide substantial benefits to ratepayers. Company witness, and then-UniSource Vice President Steven Glaser stated the following in his testimony in that proceeding:

> A further benefit of the settlement is that Citizens' gas customers will have use of approximately $30.7 million of facilities and Citizens' electric customers will have use of approximately $93.6 million of facilities that they will never have to pay for because UniSource has agreed not to seek recovery of the negative acquisition adjustments.[2]

It is hardly appropriate to now use the benefit of the negative acquisition adjustment as a reason to increase rates by including CWIP in rate base.

Q. What adjustment are you recommending?

A. I have decreased rate base by $10,761,154 to remove the Company-requested CWIP balances.

Rate Base Adjustment #4 – Accumulated Deferred Income Taxes – CIAC

Q. Have you reviewed the Company's test-year accumulated deferred income tax balances?

A. Yes. I have reviewed every item that comprises the test-year balance of $3,390,766 and the adjusted test-year balance of $1,154,741.

[2] Rebuttal Testimony of Steven Glaser, Docket No. E-01933A-02-0914, page 2.

Q. Do you agree with these balances?

A. Yes, for the most part. However, there is one deferred tax asset balance of $888,390 with which I disagree.

Q. Why do you disagree with the inclusion of this deferred tax item in rate base?

A. According to the Company, this deferred tax asset balance is attributable to CIAC taxes that were self-paid by UNS Electric. However, the Company has no related CIAC liability on its books and records. My review of the Company's Schedule B-1, FERC Form 1, and the test-year general ledger shows no FERC account 271 for CIAC.

Q. What adjustment are you recommending?

A. I have removed the CIAC related deferred tax asset of $888,390 from rate base. It is inappropriate to charge ratepayers for deferred taxes related to CIAC when the Company has not credited its rate base for the CIAC liabilities that created the tax asset.

Rate Base Adjustment #5 – Accumulated Deferred Income Taxes – A&G Capitalization

Q. Are you proposing any other adjustments to the Company's proforma ADIT balance?

A. Yes. As will be discussed in the Operating Income section of my testimony, I have made an adjustment (Operating Adjustment #10) to remove a double count in capitalized A&G expense. This adjustment will impact ADIT and, accordingly, I have increased the proforma test year ADIT balance by $116,258 to reflect this impact.

Rate Base Adjustment #6 – Working Capital

Q. Have you reviewed the Company's working capital calculations?

A. Yes. The Company's working capital request is comprised of a thirteen-month average balance for its prepayment and material and supplies accounts, and its cash working capital request is based on a lead/lag study.

Q. Do you agree with the Company's methodology?

A. Yes. Further, I have reviewed the Company's individual lag day calculations and find them to be reasonable. The only difference between the Company's calculation and RUCO's is the different level of expense recommendations. These adjustments result in a net increase in cash working capital of $1,615,255.

OPERATING INCOME

Operating Adjustment #1 – Miscellaneous Service Fees

Q. Is the Company requesting a change in its miscellaneous service fees?

A. Yes. The Company has prepared cost-of-service studies of its connect/reconnect and establishment/re-establishment fees. These studies indicate the cost to perform these services exceeds the current tariffs for these services.

Q. Do you agree that these service fees should be set at cost-of-service?

A. Yes. These services should be priced at their actual cost. If they are not, it will have the effect of having the general body of ratepayers subsidizing the customers who utilize these services.

Q. Are the Company's proposed tariffs for these services priced at cost-of-service?

A. Yes and no. Interestingly, the Company's proposed tariffs for establishment and connect services during business hours are at the cost indicated in its cost-of-service studies, however, it has priced these services for after business hours at a price below cost.

Q. Are you proposing an adjustment to the proposed tariffs for after business hours services?

A. Yes. These services need to be set at cost so the customers requesting these services are the ones that will pay the cost of these services. As shown on Schedule MDC-3, I have increased the Company's $75 fee for after hours service to $125, which is the cost indicated in the Company's cost-of-service study. This adjustment increases test year revenue by $48,648.

Operating Adjustment #6 - Bad Debt Expense

Q. Has the Company made an adjustment to increase its actual test year recorded bad debt expense?

A. Yes. The Company has calculated an average bad debt write-off percentage based on the ratio between its 2004 and 2005 account receivable write-offs and its 2004 and 2005 retail revenue. This calculation results in a bad debt write-off percentage of .36792%, which is then applied to adjusted test year revenues of $157,516,223, rendering proforma bad debt expense of $579,538.

Q. Do you agree with this calculation?

A. No. The Company's calculation overstates proforma bad debt expense because it improperly uses balance sheet accrual information to quantify test year expenses. Specifically, the Company uses balance sheet accrual account receivable write-offs to establish its bad debt expense ratio. These accruals in 2004 and 2005 were significantly higher than the amount of bad debts actually expensed on the Company's test-year income statement. Thus, when this bad debt accrual ratio is applied to test-year proforma revenues it overstates the proforma amount of bad debt expense.

Q. What adjustment have you made?

A. I have recalculated the bad debt percentage using the ratio between the actual bad debt expensed during the test year to actual test-year retail revenue. This calculation, unlike the Company's calculation, is internally consistent because it utilizes the amount of bad debts actually expensed to derive adjusted bad debt expense. As shown on Schedule MDC-3, this decreases test year expenses by $203,038.

Operating Adjustment #7 – Fleet Fuel Expense

Q. Has the Company proposed an adjustment to its test year level of fuel expense for its fleet of vehicles?

A. Yes. The Company has proposed an adjustment to annualize its fuel expense to reflect the additional employees it has included in its payroll annualization adjustment.

Q. Do you agree with this adjustment in concept?

A. Yes. The Company's payroll annualization has the effect of increasing payroll expense to recognize payroll attributable to the year-end level of employees for the entire year. The Company's proposed fleet fuel adjustment recognizes the additional fuel expense attributable to these additional employees, as well as annualizes the average cost of gasoline. Thus, conceptually, the adjustment is necessary to match these two items of expense.

Q. Do you agree with the Company's calculation of the fleet fuel expense adjustment?

A. No. The Company's calculation was based on the average fuel prices during June, July, and August of 2006. Pursuant to a data request, the Company has provided more recent data showing the average gasoline price for the first five months of 2007. Using this more recent data my adjustment results in an annualized level of fuel expense that is $53,250 less than the annualized level proposed by the Company.

Operating Adjustment #9 - Year End Accruals

Q. Has the Company proposed an adjustment to correct certain out-of-period expenses?

A. Yes. The Company has identified a number of expenses recorded in the test year that relate to prior periods as well as identified certain expenses that were recorded outside the test year that were incurred during the test year.

Q. Do you agree with this adjustment?

A. Yes. It is appropriate to adjust the test year to accurately reflect those costs that incurred during the test year. However, the Company failed to reverse one of the prior period expenses that it had identified. This expense was incurred in April 2004 but not recorded to expense until August 2005. Thus, this $6,256 expense should not be included in the test year expenses as it relates to a period prior to the test year. Accordingly, I have reduced test year expense by this amount.

Operating Adjustment #10 - A&G Capitalization

Q. Please discuss the Company's proposed adjustment to test-year Administrative and General Expense capitalization.

A. The Company proposes an adjustment that increases test year expenses by $301,187 to reclassify costs that were capitalized during the test year to the income statement.

Q. Do you agree with this adjustment?

A. No. This adjustment will result in a double count of these costs. During the test year the Company accounted for it's A&G expenses using a capitalization rate of 52.6%. Using this rate, UNS Electric capitalized

$663,975 in A&G expenses. These amounts now reside in either the Company's plant-in-service accounts or its CWIP accounts. Both of these accounts will earn a return in the proposed rates either through the return on rate base in the case of plant-in-service or through AFUDC in the case of CWIP. Further, the test-year capitalized A&G expenses of $663,975 will be recovered dollar for dollar through depreciation expense. Thus, the test-year accounting for these capitalized costs provides for their recovery in this rate case. If the Company's adjustment to reclassify some of these capitalized expenses to the income statement is accepted, ratepayers will be required to pay for them twice – once through depreciation expenses and return on rate base and again as part of operating expenses.

Q. What adjustment have you made?

A. I have reversed the Company's proposed adjustment and decreased proforma operating expenses by $301,187 to remove the double count.

Q. Are there any other problems with this proposed adjustment in addition to the double count?

A. Yes. In addition to the double count, the Company has quantified its proposed adjustment by using the new capitalization ratio it calculated for its gas division, as opposed to the new ratio it's calculated for the electric division. Correction of this error would increase the proposed capitalization rate from 28.7% to 31%. This error is somewhat moot however, since the entire adjustment appropriately should be reversed to remove the double count.

Operating Adjustment #11 – CWIP Property Taxes

Q. Has the Company proposed an adjustment for property taxes related to its CWIP balances?

A. Yes. The Company proposes to increase test-year expenses for both depreciation on its CWIP balances and property tax on its CWIP balances. I will not discuss the CWIP deprecation portion of this adjustment because it is addressed by Mr. Moore in his testimony. The property tax portion of this adjustment represents only the adjustment attributable to CWIP, and the Company has proposed a separate property tax adjustment for its overall plant. This separate property tax adjustment, related to the overall plant, is also addressed in the testimony of Mr. Moore.

Q. Do you agree with the property tax portion of the Company's CWIP expense adjustment?

A. No. As discussed previously in the rate base section of my testimony, CWIP is not used and useful and, as such, historically has not been afforded rate base recognition. Likewise, the property tax attributable to CWIP balances should not be included in test-year operating expense. My adjustment removes the Company's proforma CWIP property taxes of $239,697 from test-year expenses.

Operating Expense Adjustment #12 – Corporate Cost Allocations

Q. Did you review the Company's Corporate Cost allocations?

A. Yes. During the test year UNS Electric received $613,584 in corporation cost allocations from Tucson Electric Company (TEP). After making a proforma adjustment to that amount, the Company is requesting corporate cost allocations totaling $710,736.

Q. Have you reviewed these cost allocations?

A. The Company provided a list of each individual charge that comprised the test-year corporate cost allocations. I reviewed each cost item as well as requested copies of the invoices supporting certain allocations. I considered this review an important aspect of RUCO's audit, since the allocated expenses are related party transactions that require a high level of scrutiny.

Q. As a result of your review are you recommending an adjustment?

A. Yes. I found three categories of expenses that are not appropriately recovered from ratepayers. These categories and the amounts allocated are as follows:

1) Meals and Entertainment – Discretionary $13,773
2) Travel – Meals and Entertainment $6,799
3) Advertising - Corporate Relations/Communications $92,410

UNS Electric's test-year share of these costs was 8.86%, or $10,010. Accordingly, I have removed these costs from test-year expenses.

Operating Adjustment #14 - Valencia Turbine Fuel

Q. Has the Company proposed a proforma adjustment to include the cost of fuel to operate its Valencia Turbines in base rates?

A. Yes. The Company has increased test-year operating expenses by $266,198 to include the Valencia fuel costs.

Q. Why were there no costs included in the test year for Valencia fuel?

A. According to the Company's response to RUCO data request 2.03, the cost of the Valencia fuel was included in the test year PPFAC.

Q. Why is the Company transferring the recovery of this fuel expense from the PPFAC to base rates?

A. According to the Company's response to RUCO data request 2.03, the proforma adjustment was made to increase the base cost of fuel, yet the response also indicates that these fuel costs would be passed through the Company's proposed PPFAC.

Q. Won't this result in a double-count?

A. Yes. RUCO, like the Company, is also proposing a PPFAC that automatically adjusts based on a twelve-month rolling average. Thus, acceptance of the Company's proposed operating expense adjustment would allow recovery through base rates *and* the PPFAC.

Q. What adjustment are you recommending?

A. I have removed the $266,198 from proforma operating expenses. UNS Electric will recover these fuel costs through the new adjusting PPFAC.

Operating Adjustment #21 – Outside Services – DSM

Q. Are you proposing any adjustment for test year outside services?

A. Yes. During the test year the Company paid ECOS Consulting $49,920 to develop the Residential New Construction DSM Program (Energy Smart Homes). Going forward, the Company has proposed that the cost of all DSM programs be recovered through a DSM surcharge adjustor. I have therefore removed the ECOS Consulting costs from test year expenses because on a going forward basis these costs will be recovered through the DSM surcharge, and therefore will not recur as a part of base rates.

OTHER ISSUES

Demand Side Management (DSM)

Q. Is the Company proposing any changes to its existing DSM programs and expenditures?

A. Yes. During the test year the Company spent approximately $460,000 on two DSM programs; Low Income Weatherization and Energy Smart

Homes. The Company is proposing to more than double its DSM expenditures to $950,000. The additional funding would be used to expand the two existing DSM programs and to add a Residential HVAC Retro fit program, Shade Tree program, Education and Outreach program, Direct Load Control program, and Commercial Facilities Efficiency program. The Company requests the $950,000 funding be recovered through a surcharge that would true-up annually.

Q. Does RUCO support this proposal?

A. Yes. RUCO recognizes the value and desirability of cost-effective DSM programs. The additional funding proposed will allow for enhancement of existing programs, new programs, and consequently more savings through DSM. The more the cost of energy and generation increase, the more valuable a resource DSM becomes.

Q. Does RUCO believe the surcharge should be allowed to collect more than the requested $950,000, if spent on cost effective DSM programs?

A. Yes. To the extent that any given DSM program is approved through the Commission pre-approval process the prudent and cost-effective expenditures of the program should be recoverable through the adjustor surcharge.

Q. Does RUCO support the combining of the UNS Electric and Gas DSM programs, as proposed by the Company?

A. Yes. RUCO supports the promotion of efficiency and economies of scale where practicable.

Rules and Regulations Changes

Q. Is the Company proposing any changes to its rules and regulations of service?

A. Yes. The Company has proposed several changes to its rules and regulations of service. RUCO takes issue with one of the proposed changes.

Q. Which proposed change does RUCO take issue with.

A. The Company proposes to shorten the period of time customers have to pay their gas bills before a late fee is assessed from 15 days to 10 days, and to shorten the time customers have to pay a past due bill prior to notice of shut off from 30 days to 15 days.

Q. Why does RUCO take issue with these proposed changes?

A. The proposed changes are unreasonable. The proposed payment due dates are so short that a UNS Gas customer on vacation could foreseeably come home and find their electricity shut-off. Since electricity is a vital service to most, a more flexible payment schedule should prevail.

As a regulated utility, UNS Electric already receives a working capital allowance to bridge differences between receipt of revenues and payment of expenses, and should not have to impose unreasonable payment terms on its customers. RUCO recommends the Commission deny the proposed changes in payment due dates.

Q. Does this conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION:	University of Michigan, Dearborn B.S.A., Accounting 1989
CERTIFICATION:	Certified Public Accountant - Michigan Certified Public Accountant – Arizona
EXPERIENCE:	Audit Manager Residential Utility Consumer Office Phoenix, Arizona 85007 July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States.

Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Utility Company	Docket No.	Client
Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service

Utility Company	Docket No.	Client
United Cities Gas Company	176-717-U	Kansas Corporation Commission
General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office
Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office
Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company & Northern States Power Company	G-01970A-98-0017 & G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company & Mummy Mountain Water Company	W-01303A-98-0678 & W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company & Nicksville Water Company	W-02465A-98-0458 & W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation & ONEOK, Inc.	G-01551A-99-0112 & G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications & Citizens Utilities Company	T-01051B-99-0737 & T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-06-0009	Residential Utility Consumer Office
Black Mountain Sewer Corporation	SW-02361A-05-0657	Residential Utility Consumer Office

Utility Company	Docket No.	Client
Arizona Public Service Company	E-01345A-05-0816	Residential Utility Consumer Office
Arizona-American Water Company	WS-1303A-06-0014	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-05-0650	Residential Utility Consumer Office
UNS Gas, Inc.	G-04204A-06-0463 et al.	Residential Utility Consumer Office

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006

DOCKET NO. E-04204A-06-0783

TABLE OF CONTENTS TO RUCO SCHEDULES

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER UNS	$5,650,559	SCH. B-5, PG. 1
2	MATERIALS & SUPPLIES PER RUCO	5,650,559	SCH. B-5, PG. 1
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER UNS	351,825	SCH. B-5, PG. 1
5	PREPAYMENTS PER RUCO	351,825	SCH. B-5, PG. 1
6	ADJUSTMENT	0	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER UNS	(2,634,713)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(1,019,458)	SCHEDULE MDC-
9	ADJUSTMENT	1,615,255	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT (See RLM-4, Column (G))	$1,615,255	SUM LINES 3, 6 & 9

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-1
PAGE 2 OF 2

LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses:					
	Non-Cash Expenses					
1	Bad Debts Expense	$ 579,538	$ (203,038)	$ 376,500	0	$ -
2	Depreciation	15,594,232	(4,375,714)	11,218,518	0	$ -
3	Amortization	(3,781,658)	3,781,658	-	0	$ -
4	Deferred Income Taxes	494,521	-	494,521	0	$ -
5	Total Non-Cash Expenses	$ 12,886,633	$ (797,094)	$ 12,089,539		$ -
	Other Operating Expenses:					
6	Salaries & Wages (UNS Dir.Emp's)	$ 4,571,466	$ -	$ 4,571,466	23.33	$ 106,652,302
7	Incentive Pay (UNS Dir. Emp's)	98,247	(98,247)	-	267.00	-
8	Purchased Power	106,021,950	(266,198)	105,755,752	33.79	3,573,486,860
9	Transmission Other	7,009,878	-	7,009,878	40.67	285,091,738
10	Meter Reading	730,556	(774)	729,782	33.67	24,571,776
11	Customer Records & Collections	2,982,604	(92,900)	2,889,704	34.94	100,966,248
12	Office Supplies and Expenses	535,854	(40,614)	495,240	50.89	25,202,761
13	Injuries and Damages	512,417	(63,289)	449,128	70.52	31,672,495
14	Pensions and Benefits	1,172,133	(103,004)	1,069,129	51.37	54,921,159
15	Support Services - TEP(Dir. Labor)	5,631,155	-	5,631,155	44.77	252,106,809
16	Property Taxes	3,096,371	(649,598)	2,446,773	213.00	521,162,752
17	Payroll Taxes	348,088	(8,320)	339,768	19.87	6,751,190
18	Current Income Taxes	1,342,818	2,341,386	3,684,204	41.42	152,599,735
19	Interest on Customer Deposits	217,492	-	217,492	182.50	39,692,290
20	Other Operations and Maintenance	2,587,216	(749,803)	1,837,413	41.21	75,719,793
21	Total Other Operating Expenses	$136,858,245	$ 268,640	$137,126,885		$ 5,250,597,908
22	Total Operating Expenses	$149,744,878	$ (528,454)	$149,216,424		$ 5,250,597,908
	Other Cash Working Capital Elements:					
23	Interest on Long-Term Debt	$ 5,819,157	$ (499,676)	$ 5,319,481	90.22	$ 479,923,565
24	Revenue Taxes and Assessments	13,983,561	-	13,983,561	45.71	639,188,573
25	Total Other Cash Working Capital	$ 19,802,718	$ (499,676)	$ 19,303,042		$ 1,119,112,138
26	TOTAL			$168,519,465		$ 6,369,710,046

LINE NO.			
27	Expense Lag	Line 23, Col. (E) / (D)	37.80
28	Revenue Lag	Company Workpapers	35.59
29	Net Lag	Line 25 - Line 24	(2.21)
30	RUCO Adjusted Expenses	Col. (C), Line 23	$168,519,465
31	Cash Working Capital	Line 26 X Line27 / 365 Days	(1,019,458)
32	Company As Filed	Co. Schedule B-5, Page 1	(2,634,713)
33	ADJUSTMENT (See MDC-2, Pg 1, L 9)	Line 28 - Line 29	1,615,255

References:
Column (A): - Company Schedule B-5, Page 3
Column (B): RUCO Operating Income Adjustments (See Schedule RLM-7)
Column (C): Column (B) - (A)
Column (D): Company Schedule B-5, Page 3
Column (E): Column (C) X Column (D)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #1 - SERVICE FEES

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	# OF UNITS	FEE	REVENUE
1	ESTABLISHMENT/RE-ESTABLISHMENT	24,862	$30.00	745,860
2	CONNECT/RECONNECT - BUSINESS HOURS	2,190	$30.00	65,700
3	CONNECT/RECONNECT - AFTER BUSINESS HOURS	426	$125.00	53,250
4	ESTABLISHMENT/RE-ESTABLISHMENT - AFTER BUSINESS HOURS	547	$125.00	68,375
5	METER REREAD	62	$20.00	1,240
6	TOTAL REVENUE FROM SERVICE FEES			934,425
7	TEST YEAR REVENUE FROM SERVICE FEES			885,777
8	INCREASE IN REVENUE			$48,648

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #6 - BAD DEBT EXPENSE

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	TEST YEAR RETAIL REVENUES	$153,864,975	UNSE(0783)01732
2	LATE FEES AND MISC SERVICE	813,854	UNSE(0783)01732
3	WEATHER ADJUSTMENT	(410,061)	UNSE(0783)01732
4	CUSTOMER ANNUALIZATION	3,249,883	UNSE(0783)01732
5	CARES DISCOUNT ANNUALIZATION	(52,937)	COMPANY SCH. C-2, PG. 1
6	TOTAL REVENUE	157,465,714	SUM LINES 1 THROUGH 5
7	BAD DEBT EXPENSE RATIO	0.2391%	NOTE (a)
8	ANNUALIZED BAD DEBT EXPENSE	376,500	LINE 6 x LINE 7
9	BAD DEBTS PER COMPANY	579,538	UNSE(0783)01732
10	DECREASE IN BAD DEBT EXPENSE	($203,038)	LINE 8 -LINE 9

NOTE (a)

TEST YEAR BAD DEBT EXPENSE	$356,982
TEST YEAR REVENUE	149,302,474
RATIO	0.2391%

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #7 - FLEET FUEL EXPENSE

DOCKET NO. E-04204A-06-0783
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	AVERAGE CONSTRUCTION FTE	109.2	UNSE(0783)02106
2	AVERAGE MILES DRIVEN	14,293	UNSE(0783)02106
3	CONSTRUCTION FTE FOR JULY 2006	114.5	UNSE(0783)02106
4	2006/2007 MILEAGE	1,636,549	LINE 2 x LINE 3
5	MILES PER GALLON	7.63	UNSE(0783)02106
6	GALLONS PURCHASED	214,497	UNSE(0783)02106
7	2007 AVERAGE PRICE PER GALLON	2.77	DR STF 11.24
8	PROFORMA FUEL EXPENSE	594,157	LINE 6 x LINE 7
9	PER COMPANY	647,407	CO. SCH. C-2, PG 3
10	FUEL EXPENSE ADJUSTMENT	($53,250)	LINE 8 - LINE 9

EXHIBIT
tabbies
RUCO-9
Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT RATE DESIGN TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 12, 2007

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Account. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. On June 28, 2007 I filed direct testimony pertaining to revenue requirements in this docket.

Q. What is the purpose of your additional direct testimony?

A. The purpose of this additional testimony is to address RUCO's recommended rate design.

Q. What areas will you address in this testimony?

A. I will comment on the Company's proposed rate design and discuss the merits of RUCO's proposed rate design. RUCO witness Rodney L. Moore will sponsor RUCO's rate schedules as well as provide a typical bill analysis of RUCO's proposed residential rates.

COMPANY PROPOSED RATE DESIGN

Q. What modifications is the Company proposing to its current rate design?

A. The Company is proposing the following modifications to its current rate design:

1) Implementation of mandatory Time of Use (TOU) rates for all new residential customers;
2) Fuel and purchased power adjustor (PPFAC);
3) Shift a portion of the commodity charges to the fixed charge;
4) Implementation of a surcharge to recover Demand Side Management (DSM) costs;
5) Step rate increase for June 2008;
6) Inverted block (tier) rate structure;
7) Elimination of separate rate structures for Mohave and Santa Cruz counties; and
8) Restructuring of the Cares discount.

Q. Do you agree with all of these proposed rate design modifications?

A. No, not in their entirety.

Q. Please explain.

A. I have already addressed RUCO's position regarding modifications to the PPFAC, DSM, and the proposed step increase in my June 28, 2007 testimony, and will not repeat those positions here. The remaining proposed modifications are addressed below.

Q. Do you agree with the elimination of separate rates for Mohave and Santa Cruz Counties?

A. Yes. Under UNS Electric's new ownership, these systems are operated as one entity for which there is one cost of service. Thus, there is no reason for a disparity as there was under Citizens operation and ownership.

Q. Do you agree that a portion of the current commodity charge should be shifted to the fixed monthly minimum?

A. No. The Company has presented no evidence supporting such a shift in revenue recovery, and RUCO believes the strong price signal that the current rates send regarding consumption should be continued. Accordingly, RUCO's recommended rate design maintains the current fixed/variable rate ratio.

Q. Do you agree with the proposed inverted tier structure?

A. Yes. Currently residential customers pay a flat commodity rate, regardless of the level of consumption. The proposed inverted tier structure sends a stronger price signal by charging a higher cost for consumption over 400 kWh. RUCO's recommended rate design includes a two-tier inverted rate structure.

Q. Do you agree with the Company-proposed TOU rates for residential customers?

A. Yes. Currently, TOU rates are not offered for residential customers. Thus, the addition of this rate schedule is a big plus that will allow the Company to further shave peak load, while at the same time providing an incentive for customers to shift load and save money.

Q. Do you agree that TOU rates should be mandatory for all new customers, as proposed by the Company?

A. Yes, in UNS Electric's circumstances I believe this is appropriate.

Q. Please explain.

A. Currently, UNS Electric has no time of use rates for residential customers. APS, and to a lesser extent TEP, have offered TOU rates for residential customers for years. In fact, the majority of APS' residential customers are on TOU rates, which has allowed APS to significantly alter its load curve. UNS Electric however, must start from ground zero; therefore. the mandatory aspect of these new rates for new customers is crucial in jumpstarting a meaningful load shifting program.

Q. Are you recommending any exceptions to the mandatory TOU rates?

A. Yes, but only in limited circumstances. At the time a new customer requests service, UNS Electric's customer service representatives would be required to pose a series of questions to the customer to determine if the customer had special circumstances that would result in TOU rates creating a hardship. Examples of hardship would include persons dependent on life support equipment, or other handicaps that would prevent the customer from shifting load. Also the customer service representatives should determine if the new customer is low-income, thereby qualifying for the CARES TOU rates, and advise qualified customers of the availability of that rate. Lastly, all customers should be fully advised of how the TOU rates work and how they can maximize their savings on TOU rates. Upon connection, the same information should be provided in written format.

Q. Does RUCO support the Company's proposed changes to the CARES discount?

A. Yes. Currently, the CARES discount is applied to customers' volumetric charges on a declining basis. The first 300 kWh is discounted at 30%, the next 300 kWh at 20%, and the next 400 kWh at 10%. The discount is capped at $8.00 for usage over 1000 kWh. Under this rate structure, only the largest users receive the maximum benefits from the CARES discount. UNS Electric's proposed CARES discount, however, is a flat discount of

$8.00 per bill, which would allow even the lowest users to receive the maximum benefit of the discount.

RENEWABLE ENERGY STANDARD AND TARIFF (REST)

Q. Has the Company proposed a new tariff to comply with the REST rules?

A. No. The new REST rules were only recently certified by the Attorney General, and thus were not effective at the time UNS Electric filed the instant rate application.

Q. Does the Company currently have a renewables tariff?

A. Yes. The Company currently has in place an Environmentally Friendly Portfolio Surcharge (EFPS) that was put in place August 11, 2003 pursuant to R-14-2-1618, the Environmental Portfolio Standard. Since this rule is now outdated by the REST rule, RUCO would expect that the Company in rebuttal testimony would propose a new tariff that would comport with the recently confirmed REST rules, and at that time RUCO will respond.

Q. Does this conclude your additional direct testimony?

A. Yes.

EXHIBIT
tabbies
RUCO-10
Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

SURREBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

August 24, 2007

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in this docket on June 28, 2007 and July 12, 2007.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony I will respond to the positions and arguments set forth by various UNS Electric witnesses in their rebuttal testimony. I will show that certain arguments are without merit and demonstrate why such arguments should be rejected.

Q. What issues will you address in your surrebuttal testimony?

A. I will address the following issues in my surrebuttal testimony:

Generation

* Black Mountain Generating Station
* Purchased Power and Fuel Adjustor Clause

Rate Base

* CWIP
* Accumulated Deferred Income Taxes - CIAC
* Accumulated Deferred Income Taxes – A&G Capitalization

Operating Income

- Miscellaneous Service Fees
- Bad Debt Expense
- Fleet Fuel Expense
- Year-end Accruals
- A&G Capitalization
- CWIP Property Taxes
- Corporate Cost Allocations
- Valencia Turbine Fuel
- Outside Services – DSM

Rate Design

GENERATION

Black Mountain Generating Station

Q. Please discuss the Company's rebuttal comments pertaining to RUCO's recommended ratemaking treatment of the Black Mountain Generating Station (BMGS).

A. The Company claims that not rate basing the BMGS at this juncture (prior to even being built) is short-sighted and that a determination of prudency on this related party transaction is warranted now. The Company further argues that the requested ratemaking treatment does not violate Arizona ratemaking principles.

Q. Please explain.

A. First, the Company argues that the known and measurable principle is not violated because by the time June 2008 arrives, and the proposed step rate increase for the BMGS goes into effect, the costs will be known and measurable. Further, UNS Electric argues that because it has limited its request to $60 million, regardless of actual costs, that the $60 million is in fact known and measurable.

Q. Please respond.

A. Despite these arguments, the fact remains that the Company is requesting rate base authorization for an asset that does even exist as yet. By no standard can this meet the known and measurable principle. Further, the fact that the Company has agreed to limit its rate request in this case to $60 million for the BMGS only renders the price known and measurable for this case. The Company fully intends to recover the actual completed cost of BMGS in its next rate case. Thus, the ultimate cost to ratepayers is not known and measurable at this juncture.

Q. Please discuss the Company's matching principle argument.

A. The Company claims that the BMGS will be serving existing customers and therefore does not violate the matching principle of ratemaking.

Q. Do you agree?

A. No. The Company's proposal does violate the matching principle in that the customer count in June 2008 will be different[1] than the customer count included in this rate case based on a test year ended December 2006. The Company's proposal would have rate recognition of this additional investment yet ignore the increased revenue due to growth.

Q. Please discuss the Company's comments related to the historical test-year principle.

A. The Company appears to acknowledge that this principle is violated by its proposal, yet argues that such violation is justified because its purchased power contract with APS will expire outside of the test year.

Q. Does that fact justify the authorization to rate base assets that do not even exist at this time?

A. No. Until such time as the asset actually exists, there is no basis for rate base authorization.

Q. Please discuss the used and useful argument.

A. The Company indicates that it plans to file a completion report in June 2008 that will confirm the plant is used and useful.

[1] The customer count will most likely be greater in 2008 than it was during the test year given the historical growth rate.

Q. Please respond.

A. Again, the Company wants approval of rate recovery of this plant prior to its construction, let alone in-service date. This does not meet the used and useful standard.

Q. Please discuss the Company's rebuttal comments regarding related party transactions.

A. The Company argues that because it committed to acquire the BMGS at "cost" that the fact that this is a related party transaction should not be a concern.

Q. Please respond.

A. Precisely because the ultimate "cost" of this asset is under the control of a related party is cause for concern.

Q. Do you continue to retain your position on this issue as set forth in your direct testimony?

A. Yes. The Company's ratemaking proposal for the BMGS is premature and violates all ratemaking principles. As stated in my direct testimony, the Company is free to acquire power from the BMGS once it is completed and to have timely recovery of those costs through RUCO's proposed PPFAC. Once the BMGS is completed and in-service if the Company continues to believe acquisition of the BMGS is a good idea, then it can request rate base recovery at that time.

Purchased Power and Fuel Adjustment Clause (PPFAC)

Q. Please discuss the Company's rebuttal comments pertaining to the PPFAC.

A. In its rebuttal testimony, the Company changes the PPFAC it proposed in its direct testimony to adopting the Staff-proposed PPFAC.

Q. How does the Company's new proposed PPFAC differ from its original proposal?

A. The primary difference is that the Company now proposes that the PPFAC rate be set based on estimated projected fuel and purchased power costs instead of a historical twelve-month rolling average.

Q. Do you agree with the Company's new proposal?

A. No. I believe the historical twelve-month rolling average as originally proposed is a superior methodology. The rolling average methodology allows for a price signal when costs increase or decrease while at the same time smoothing any wide fluctuations. Further, the rolling average methodology, as modified by RUCO, provides a number of safeguards and protections including a cap on the magnitude by which the surcharge can move in a given year, and a 90/10 sharing mechanism that is designed to incent the Company to control its fuel and purchased power costs.

Q. The Company argues that its rebuttal proposed PPFAC is patterned after a PSA recently authorized for APS. Please comment.

A. The Company's proposed PPFAC is very similar to a PSA recently authorized for APS. However, I would note that APS' fuel and purchased power requirements are of an entirely different nature than UNS Electric. APS' PSA is comprised primarily of fuel costs, since APS owns the majority of its generation. UNS Electric is subject primarily to market prices and purchased power contracts. The historical price of these procurements is a more accurate measure of these costs than market projections. Thus, I believe the PPFAC methodology as proposed by RUCO is a better solution to fuel and purchased power recovery than either the Company or Staff's proposed methodology.

RATE BASE

Rate Base Adjustment #3 - Construction Work in Progress (CWIP)

Q. Please discuss the Company's rebuttal comments regarding CWIP.

A. The Company argues that CWIP in rate base is an accepted ratemaking concept that is routinely recognized in many states. The Company further expounds that, contrary to my testimony, CWIP inclusion in rate base does not require extraordinary circumstances.

Q. Please respond.

A. While CWIP in rate base may be accepted ratemaking treatment in some states, it is not accepted ratemaking in Arizona. In fact, Arizona has always required extraordinary circumstances before it even considered rate base treatment for CWIP. The Commission explicitly stated such in Decision No. 54247:

> Beginning in Decision No. 53909 (January 30, 1984) and again in Decision No. 54204, the Commission has recognized that the **extraordinary** inclusion of Palo Verde CWIP necessitates an equally extraordinary reward to ratepayers for their admittedly involuntary investment in Palo Verde carrying costs. [Decision No. 54247, dated November 28, 1984, page 5-6]

Q. What other arguments does the Company make on the CWIP issue?

A. The Company further argues that RUCO's exclusion of CWIP from rate base creates a mismatch because some of those projects have CIAC balances associated with them, which are included in the test-year rate base.

Q. Please respond.

A. As just discussed, Arizona has historically excluded CWIP in rate base and historically included CIAC in rate base. Thus, under RUCO's recommendations, UNS Gas is being afforded the same rate base treatment for these two items that every other utility in Arizona is afforded.

Q. In fact, isn't it the Company's proposal to rate base CWIP that creates a mismatch?

A. Yes. Mismatches result from the Company's CWIP proposal because while it has included its investment in CWIP in rate base, it has failed to recognize the additional revenues those construction projects will generate.

Rate Base Adjustment # 4 – Accumulated Deferred income Taxes – CIAC

Q. Please discuss the Company's rebuttal comments pertaining to your CIAC ADIT adjustment.

A. The Company argues that RUCO has confused water and wastewater CIAC accounting with electric CIAC accounting. UNS claims that electric utilities do not have a separate CIAC account, but rather any CIAC funds are credited directly to the plant accounts.

Q. Do you agree with this argument?

A. No. The NARUC Uniform System of Accounts for A & B Electric companies contains an account 271 for CIAC. Thus, the Company is wrong that such an account is only used for water and wastewater utilities. Since there is no CIAC balance in UNS Electric's account 271 I have removed the deferred income taxes related to these non-existent balances.

Rate Base Adjustment #5 – Accumulated Deferred Income Taxes (ADIT) – A&G Capitalization

Q. Please discuss the Company's rebuttal comments pertaining to your A & G Capitalization Adjustment.

A. The Company does not agree with my A & G Capitalization adjustment and therefore objects to my companion adjustment to ADIT.

Q. What is your position?

A. As is discussed in the Operating Income section of my testimony I believe my recommended A & G Capitalization adjustment is necessary and appropriate, and therefore I continue to recommend the companion adjustment to ADIT.

OPERATING INCOME

Operating Adjustment #1 – Miscellaneous Service Fees

Q. Please discuss the Company's rebuttal comments regarding RUCO's recommendation to set miscellaneous service charges at cost.

A. The Company states that it does not object to this recommendation.

Operating Adjustment #6 – Bad Debt Expense

Q. Please discuss the Company's rebuttal comments regarding RUCO's Bad Debt expense adjustment.

A. In its rebuttal testimony[2] the Company acknowledges that it has erroneously calculated its bad debt expense using gross bad debt write-offs as opposed to the net bad debt expense. Thus, the Company agrees with this portion of my bad debt expense adjustment.

Q. Is this issue no longer in contention?

A. No. While the Company agrees that the bad debt ratio should be based on net bad debt expense write-off, it argues that this ratio should be applied to the average bad debt expense over several years.

Q. Do you agree?

A. No. The Company has this propensity to use average expense levels for purposes of setting rates as opposed to test year actuals. This methodology is known as normalization and should only be applied when specific abnormal conditions are identified in the test year data. The Company has presented no evidence of events that transpired during the test year that would render special normalization treatment for its bad debt expense. My adjustment uses the actual net bad debt ratio and applies it

[2] Rebuttal Testimony of Dallas Dukes at page 21, lines 22-24

to RUCO's adjusted revenue. This is the appropriate ratemaking treatment.

Operating Adjustment #7 – Fleet Fuel Expense

Q. Please discuss the Company's rebuttal comments regarding the Fleet Fuel Adjustment.

A. In its rebuttal testimony the Company agrees with RUCO and the Staff that the cost of fuel used in this adjustment should be updated to reflect current costs. The Company uses an updated figure of $2.82 per gallon. While different than RUCO's updated number, RUCO is willing to accept the Company's position as reasonable.

Operating Adjustment # - 9 Year-end Accruals

Q. Please discuss the Company's rebuttal comments regarding your year-end accrual adjustment.

A. The Company agrees with this adjustment to remove out-of test year expense accruals.

Operating Adjustment #10 – A&G Capitalization

Q. Please discuss the Company's rebuttal comments regarding your A&G Capitalization adjustment.

A. The Company defends its adjustment to increase test year expenses by $301,187 to reclassify costs that were capitalized during the test year by arguing that this is a "prospective adjustment" that is recurring and therefore appropriate.

Q. Please respond.

A. It appears the Company is insistent that its capitalization rate during the test-year is too high and over $300,000 in test-year capitalized costs should be reclassified to expense. However, it appears the Company wants to have it both ways.

Q. Please explain.

A. If the Company is insistent that it capitalized too much A&G expense during the test year - it cannot simply increase its expenses without making the corresponding adjustment to decrease its rate base to remove the amount it no longer intends to capitalize. Thus, if the Company continues to insist on reclassifying test year capitalized expenses to test year expenses, it needs to reduce the rate base by the same amount that it is increasing expenses.

Operating Expense Adjustment #11 – CWIP Property Taxes

Q. Please discuss the Company's rebuttal arguments regarding CWIP property taxes.

A. As discussed earlier in the rate base section of my surrebuttal testimony, the Company continues to argue that its CWIP balances should be afforded rate base treatment. Likewise, it argues that it should be allowed recovery of property taxes related to those CWIP balances.

Q. Please respond.

A. Again, as discussed in the rate base section of my testimony, rate base treatment of CWIP is extraordinary ratemaking for which the Company has provided no compelling justification. Likewise, property taxes associated with CWIP should not be recovered through rates.

Q. Does the ADOR assess property taxes on CWIP?

A. No. The formula the ADOR uses to assess property taxes does not include CWIP balances. Thus, the Company has no liability for CWIP property taxes and no need for rate recovery of such taxes. The Company's proposal is unnecessary and results in higher rates.

Operating Income Adjustment # 12 - Corporate Cost Allocations

Q. Please discuss the Company's rebuttal comments regarding RUCO's Corporate Cost Allocation adjustment.

A. The Company has accepted $1,823 of this adjustment related to allocations of Discretionary Meals & Entertainment and Travel Meals & Entertainment. The Company argues that the remaining $8,187 of this adjustment related to Advertising – Corporate Relations/Communications should be allowed.

Q. Do you agree?

A. No. As discussed in my direct testimony, these expenses primarily benefit shareholders and as such should appropriately be recovered from shareholders.

Operating Adjustment #14 – Valencia Turbine Fuel

Q. Please discuss the Company's rebuttal comments pertaining to RUCO's Valencia Fuel adjustment.

A. The Company continues to maintain that its test year expenses should be increased by $265,198 to include its estimated cost of Valencia Fuel. It argues that the adjustment is necessary to "accurately reflect the base cost of fuel and purchased power and energy".

Q. Do you agree with this argument?

A. As discussed in my direct testimony, the Company acknowledged that these costs were to be recovered through the proposed PPFAC. RUCO supports the concept of a twelve-month average adjusting PPFAC, and accordingly on a going forward basis these costs will be recovered through the PPFAC mechanism and not base rates.

Operating Income Adjustment #21 – Outside Services DSM

Q. Please discuss the Company's rebuttal comments regarding your Outside Services adjustment.

A. The Company indicates that it agrees with my adjustment to remove $49,920 in DSM expenses from the test year since it intends to prospectively recover all DSM related expenditures through a surcharge. However, UNS claims that $32,865 of this amount was already removed as part of its own DSM and renewables adjustment.

Q. Do you agree?

A. No. The Company provided workpapers detailing each item that was included in its DSM and renewables adjustment. None of the invoices included in my $49,920 DSM adjustment are included in the Company's DSM and renewables adjustment. Thus, it is necessary to remove the entire $49,920 from test-year expenses as these costs will be recovered through the DSM surcharge proposed in this case.

Operating Adjustment #22 – Income Tax Expense

Q. Please discuss the Company's rebuttal comments regarding RUCO's income tax expense adjustment.

A. The Company argues that RUCO income tax calculation is incorrect because it does not separate current income tax expense from deferred income tax expense.

Q. Do you agree with this criticism?

A. No. It is standard practice in ratemaking to account for income tax *expense* on a current basis. The accounting for tax timing differences is appropriately reflected for ratemaking purposes in the *rate base*. Tax timing differences that are assets (i.e. the Company pays taxes to the IRS prior to receiving payment from ratepayers) are reflected as rate base additions and tax timing differences that are liabilities (i.e. ratepayers pay the taxes to the Company prior to the Company paying the IRS) are reductions to rate base. In this manner, ratepayers and the Company are credited or debited with the impact of deferred income taxes. Thus, it is inappropriate to repeat this process on the income statement as suggested by the Company.

RATE DESIGN

Q. Please discuss the Company's rebuttal comments regarding RUCO's propped rate design.

A. The Company is generally supportive of RUCO's proposed rate design including RUCO's acceptance of rate consolidation, mandatory TOU rates, inverted block rates, and modifications to the CARES discount.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006

SURREBUTTAL
TABLE OF CONTENTS TO RUCO SCHEDULES

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. E-04204A-06-0783
SCHEDULE SURR MDC-1

SURREBUTTAL

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER UNS	$5,650,559	SCH. B-5, PG. 1
2	MATERIALS & SUPPLIES PER RUCO	5,650,559	SCH. B-5, PG. 1
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER UNS	351,825	SCH. B-5, PG. 1
5	PREPAYMENTS PER RUCO	351,825	SCH. B-5, PG. 1
6	ADJUSTMENT	0	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER UNS	(2,634,713)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(1,055,056)	SCHEDULE MDC-
9	ADJUSTMENT	1,579,657	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT (See RLM-4, Column (G))	$1,579,657	SUM LINES 3, 6 & 9

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

SURREBUTTAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses:					
	Non-Cash Expenses					
1	Bad Debts Expense	$ 579,538	$ (203,038)	$ 376,500	0	$ -
2	Depreciation	15,594,232	(4,492,305)	11,101,927	0	$ -
3	Amortization	(3,781,658)	3,781,658	-	0	$ -
4	Deferred Income Taxes	494,521	-	494,521	0	$ -
5	Total Non-Cash Expenses	$ 12,886,633	$ (913,685)	$ 11,972,948		$ -
	Other Operating Expenses:					
6	Salaries & Wages (UNS Dir.Emp's)	$ 4,571,466	$ -	$ 4,571,466	23.33	$ 106,652,302
7	Incentive Pay (UNS Dir. Emp's)	98,247	(98,247)	-	267.00	-
8	Purchased Power	106,021,950	(266,198)	105,755,752	33.79	3,573,486,860
9	Transmission Other	7,009,878	-	7,009,878	40.67	285,091,738
10	Meter Reading	730,556	(618)	729,938	33.67	24,577,022
11	Customer Records & Collections	2,982,604	(91,308)	2,891,296	34.94	101,021,877
12	Office Supplies and Expenses	535,854	(39,280)	496,574	50.89	25,270,670
13	Injuries and Damages	512,417	(80,013)	432,404	70.52	30,493,121
14	Pensions and Benefits	1,172,133	(103,004)	1,069,129	51.37	54,921,159
15	Support Services - TEP(Dir. Labor)	5,631,155	-	5,631,155	44.77	252,106,809
16	Property Taxes	3,096,371	(596,407)	2,499,964	213.00	532,492,377
17	Payroll Taxes	348,088	(8,320)	339,768	19.87	6,751,190
18	Current Income Taxes	1,342,818	2,340,043	3,682,861	41.42	152,544,114
19	Interest on Customer Deposits	217,492	-	217,492	182.50	39,692,290
20	Other Operations and Maintenance	2,587,216	(739,078)	1,848,138	41.21	76,161,770
21	Total Other Operating Expenses	$136,858,245	$ 317,571	$137,175,816		$ 5,261,263,299
22	Total Operating Expenses	$149,744,878	$ (596,114)	$149,148,764		$ 5,261,263,299
	Other Cash Working Capital Elements:					
23	Interest on Long-Term Debt	$ 5,819,157	$ (501,147)	$ 5,318,010	90.22	$ 479,790,902
24	Revenue Taxes and Assessments	13,983,561	-	13,983,561	45.71	639,188,573
25	Total Other Cash Working Capital	$ 19,802,718	$ (501,147)	$ 19,301,571		$ 1,118,979,475
26	TOTAL			$168,450,335		$ 6,380,242,774

LINE NO.	DESCRIPTION	SOURCE	AMOUNT
27	Expense Lag	Line 23, Col. (E) / (D)	37.88
28	Revenue Lag	Company Workpapers	35.59
29	Net Lag	Line 25 - Line 24	(2.29)
30	RUCO Adjusted Expenses	Col. (C), Line 23	$168,450,335
31	Cash Working Capital	Line 26 X Line27 / 365 Days	(1,055,056)
32	Company As Filed	Co. Schedule B-5, Page 1	(2,634,713)
33	ADJUSTMENT (See MDC-2, Pg 1, L 9)	Line 28 - Line 29	1,579,657

References:
Column (A): - Company Schedule B-5, Page 3
Column (B): RUCO Operating Income Adjustments (See Schedule RLM-7)
Column (C): Column (B) - (A)
Column (D): Company Schedule B-5, Page 3
Column (E): Column (C) X Column (D)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
OPERATING ADJ #7 - FLEET FUEL EXPENSE

DOCKET NO. E-04204A-06-0783
SURREBUTTAL SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	AVERAGE CONSTRUCTION FTE	109.2	UNSE(0783)02106
2	AVERAGE MILES DRIVEN	14,293	UNSE(0783)02106
3	CONSTRUCTION FTE FOR JULY 2006	114.5	UNSE(0783)02106
4	2006/2007 MILEAGE	1,636,549	LINE 2 x LINE 3
5	MILES PER GALLON	7.63	UNSE(0783)02106
6	GALLONS PURCHASED	214,497	UNSE(0783)02106
7	2007 AVERAGE PRICE PER GALLON	2.82	DR STF 11.24
8	PROFORMA FUEL EXPENSE	604,882	LINE 6 x LINE 7
9	PER COMPANY	647,407	CO. SCH. C-2, PG 3
10	FUEL EXPENSE ADJUSTMENT	($42,525)	LINE 8 - LINE 9

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 28, 2007

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utility regulation and your educational background.

A. I have been involved with utility regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of UNS Electric, Inc.'s ("UNS" or "Company") application for a permanent rate increase ("Application") for the Company's electric distribution operations in Mohave and Santa Cruz Counties. UNS filed the Application with the ACC on December 15, 2006. The Company has chosen the fiscal year ended June 30, 2006 for the test year in this proceeding.

Q. Briefly describe UNS.

A. UNS is a wholly owned subsidiary of UniSource Energy Services, which is owned by UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")[1]. UniSource is also the parent company of Tucson Electric Power, the second largest investor owned electric utility in the state. In addition to the electric distribution operations of UNS, UniSource also provides natural gas distribution service through its other subsidiary UNS Gas, Inc., to customers in Northern Arizona and Santa Cruz County.

...

[1] NYSE ticker symbol UNS.

Q. Please explain your role in RUCO's analysis of UNS' Application.

A. I reviewed UNS' Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of debt (the Company has no preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UNS?

A. No. In 2003 I was involved with UniSource's acquisition of UniSource Energy Corporation's gas and electric assets from Citizens' Utilities Company. The UNS entity was the result of that acquisition and the Company's present rates were established in that proceeding. More recently I provided cost of capital testimony in a rate case proceeding that involved UNS Gas, Inc.[2]

...

[2] Docket No. G-04204A-06-0463

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. No. RUCO witnesses Marylee Diaz Cortez, CPA and Rodney L. Moore handled those aspects of the Company's Application.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the current economic climate that UNS is operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on UNS' cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of UNS, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.30 percent cost of equity capital. This 9.30 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending that the Commission adopt the Company-proposed 6.36 percent cost of short-term debt and 8.22 percent cost of long-term debt. This is based on my review of the costs associated with UNS' various debt instruments and credit facilities.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 3.97 percent short-term debt, 47.18 percent long-term debt and 48.85 percent common equity, be adopted by the Commission.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and cost of debt analyses, I am recommending an 8.67 percent cost of capital for UNS. This figure represents the weighted cost of my recommended cost of common equity and my recommended costs of short and long-term debt.

Q. Why do you believe that your recommended 8.67 percent cost of capital is an appropriate rate of return for UNS to earn on its invested capital?

A. The 8.67 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as UNS, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for UNS?

A. Based on the results of my DCF and CAPM analyses, which ranged from 7.89 percent to 11.56 percent for a sample of electric providers, I am recommending a 9.30 percent cost of equity capital for UNS. My recommended 9.30 percent figure represents an average of the results of my DCF and CAPM analyses, which utilized a sample of publicly traded electric companies.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate UNS' cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine UNS' cost of equity capital. It is similar to one of the models used by the Company.

Q. In determining the rate of future dividend growth for UNS, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

...

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change only in the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

...

[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

...

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	$1 - [(BV) \div (MP)]$
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation $[(M \div B) + 1] \div 2$.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used $[(M \div B) + 1] \div 2$ as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In the most recent Southwest Gas Corporation rate case[7], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case,

[7] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of eight electric utility companies that have similar operating characteristics to UNS.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of UNS?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with UNS itself. Although shares of UNS' parent company, UniSource, are traded on the NYSE, there is no financial data available on dividends paid on *publicly held* shares of UNS. Consequently it was necessary to create a proxy by analyzing publicly traded electric companies with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the <u>Hope</u> decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the companies that make up your proxy for UNS?

A. All of the electric utility companies in my sample, with the exception of MG Energy Inc., are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") electric utility (east, central and west) industry segments. MG Energy Inc. is traded on the NASDAQ[8] which is also a major U.S. stock exchange. Each of the companies in the proxy are engaged in the provision of regulated electric utility services. Attachment A of my testimony contains Value Line's most recent evaluation of the electric utility proxy group that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. The eight electric companies included in my proxy (and their NYSE/NASDAQ ticker symbols) are CH Energy Group, Inc. ("CHG"), Cleco Corporation ("CNL"), Hawaiian Electric Industries, Inc. ("HE"), MG

[8] National Association of Securities Dealers Automated Quotation system

Energy Inc. ("MGEE"), Northeast Utilities ("NU"), NSTAR ("NST"), Puget Energy, Inc. ("PSD"), and UIL Holdings ("UIL").

Q. Briefly describe the regions of the U.S. served by the eight electric utilities that make up your sample proxy.

A. The eight electric utilities listed above provide electric and natural gas services to customers in New England (i.e. NU which serves Connecticut, New Hampshire and the western half of Massachusetts; NST which serves the eastern half of Massachusetts including Boston; and UIL which provides electricity to the southern portion of Connecticut), the Middle Atlantic region (i.e. CHG which serves 293,000 customers in the Mid-Hudson Valley region of New York state), the Midwest (i.e. MGEE which provides service to customers in the Madison, Wisconsin area), the South (i.e. CNL which supplies electricity to 267,000 customers in the central part of Louisiana), the Pacific Northwest (i.e. PSD which serves western Washington state), and the Hawaiian islands (i.e. HE which provides electrical service to 434,000 customers on the islands of Oahu, Maui, Molokai, Lanai and Hawaii).

Q. Did the Company's witness also perform a similar analysis using electric utility companies?

A. Yes, the Company's witness, Kentton C. Grant performed a similar analysis of publicly traded electric utility companies.

Q. Does your sample of electric utilities include all of the same companies that Mr. Grant included in his sample?

A. Yes. My sample includes the same eight electric utility companies that Mr. Grant included in his sample.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2002 to 2006. Schedule WAR-5 also includes Value Line's projected 2007, 2008 and 2010-12 values for the retention ratio, return on book equity, book value per share growth rate, and number of shares outstanding for the electric utility companies in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Hawaiian Electric Industries, Inc., (NYSE symbol HE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 9 and 10 of my testimony) to multiply HE's earned return on common equity by its earnings retention ratio for each year in the 2002 to 2006 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, HE's sustainable internal growth rate ranged from 2.65 percent in 2002 to 0.67 percent in 2006. The company's growth rates experienced a declining pattern during the majority of the observation period, which resulted in a 1.58 percent average over the 2002 to 2006 time frame. Value Line's analysts are forecasting a further decline through 2007 before the trend reverses itself and growth increases to a level of 3.50 percent during the 2010-12 period. Value Line believes that earnings will increase by 4.00 percent but dividend growth will remain flat. Value Line has also decreased its book value growth projection downward from 2.50 percent to 0.50 percent. Based on the aforementioned projections, I believe that a 3.35 percent rate of internal sustainable growth is reasonable for HE.

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that HE's share growth averaged 2.56 percent over the 2002 - 2006 observation period. However, Value Line expects future outstanding shares to increase modestly from 83.50 million in 2006 to 87.00 million by the end of 2012. Taking this data into consideration, I am estimating a 2.00 percent rate of share growth for HE. My final dividend growth rate estimate for HE is 4.22 percent (3.35 percent internal + 0.87 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 3.94 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. As can be seen in Schedule WAR-6, my 3.94 percent estimate is 74 basis points higher than the 3.20 percent average of Value Line's and Zacks Investment Research's ("Zacks") projected and historic averages of earnings per share, dividends per share and book value per share. My 3.94 percent estimate is also 238 basis points higher than Value Line's 1.56 percent 5-year historic compound history. Both the Value Line and Zacks earnings projections (Attachment B) indicate that investors are expecting increased performance from electric utility companies in the future. Based on the information presented in Schedule WAR-6, I would say that my 3.94 percent estimate is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's most recent (i.e. March 30, May 11, and June 1, 2006) Ratings and Reports for the Electric Utility (Central, West and East) Industry updates. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period April 16, 2007 to June 8, 2007.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 7.89 percent.

...

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[9], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[10] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities),

[9] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[10] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß \,(r_m - r_f)\,]$$

where: k = cost of capital of a given security,

r_f = risk-free rate of return,

ß = beta coefficient, a statistical measurement of a security's systematic risk,

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[11] This resulted in a risk-free (r_f) rate of return of 5.05 percent.

[11] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from May 4, 2007 to June 8, 2007.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of the historical yields of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[12] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument).

[12] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2006 as the proxy for the market rate of return (r_m). The information was obtained from Morningstar's <u>SBBI Yearbook,</u> which publishes historical data on stock returns, U.S. Treasury yields and rates of inflation. The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 5.55 percent (10.40% - 4.85% = <u>5.55%</u>). The risk premium that results by using the arithmetic mean calculation for r_m is 7.45 percent (12.30% - 4.85% = <u>7.45%</u>).

Q. How did you select the beta coefficients that were used in your CAPM model?

A. The beta coefficients (ß), for the electric utilities used in my proxy, were calculated by Value Line and were published in the most recent updates (i.e. March 30, May 11, and June 1, 2007) for the Central, West and East regional electric providers in my sample. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.75 to 1.30 with an average beta of 0.90.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 9.85 percent. My calculation using an arithmetic mean results in an average expected return of 11.56 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	**RESULTS**
DCF	7.89%
CAPM	9.85% – 11.56%

Based on these results, my best estimate of an appropriate range for a cost of common equity for UNS is 7.89 percent to 11.56 percent. My final recommendation for UNS is 9.30 percent.

Q How did you arrive at your recommended 9.30 percent cost of common equity?

A. My recommended 9.30 percent cost of common equity is the average of my DCF and CAPM results. The calculation can be seen on Page 3 of Schedule WAR-1.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.80 percent cost of equity capital proposed by the Company is 250 basis points higher than the 9.30 percent cost of equity capital that I am recommending.

...

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board

("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[13] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve

[13] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of

2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding the recession that the U.S. now appears to have recovered from.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates, moves which indicated that the worst may be over and that the current recession might have bottomed out during the last quarter of 2001, a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[14]"

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

...

[14] Wolk, Martin, "Fed leaves short-term rates unchanged," MSNBC, January 28, 2004.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief. As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to its current level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What has been the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the existing federal funds rate of 5.25 percent, where it has stood since June 29, 2006.

...

Q. How have analysts viewed the Fed's actions over the last five years?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[15] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[16]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings, like the one that the Fed managed to pull off during the 1994 – 1995 time frame, in which a recession or a bear market were avoided rarely happen[17]. Since it began increasing the federal funds rate in June 2004, the Fed has assured investors that it would increase rates at a "measured" pace. Many analysts

[15] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[16] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[17] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[18]. According to Mr. Browning, the hope, at the time that his article was published, was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Has the Fed's attempt to engineer a soft landing been successful to date?

A. It would appear so. Articles published in the mainstream financial press have been generally upbeat on the current economy. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[19]

[18] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

[19] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2001 affected benchmark rates?

A. Despite the increases by the FOMC, interest rates and yields on U.S. Treasury instruments are for the most part still at historically low levels. The Fed's actions have also had the overall effect of reducing the cost of many types of business and consumer loans. As can be seen in Schedule WAR-8, with the exception of the federal discount rate (the rate charged to member banks), which has increased to 6.25 percent from 5.73 percent in 2000, the other key interest rates (i.e. the prime rate and the federal funds rate) are still below their year-end 2000 levels.

Q. What has been the trend in other leading interest rates over the last year?

A. As of June 8, 2007, the leading interest rates are showing mixed results. The prime rate has increased from 8.00 percent a year ago to its current level of 8.25 percent. The benchmark federal funds rate, just discussed, has increased from 5.00 percent, in June 2006, to its current level of 5.25 percent (the result of the seventeen quarter point increases noted earlier). The yields on several maturities of U.S. Treasury instruments have increased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[20], in which long-term rates fell as short-term rates increased, thus creating the somewhat inverted yield curve that existed as of June 8, 2007 (Attachment C), appears to have

[20] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

ended and a more traditional yield curve (where yields increase as maturity dates lengthen) appears to be forming. The 91-day T-bill rate, used in my CAPM analysis, has increased slightly from 4.82 percent, in June 2006, to 4.83 percent as of June 8, 2007. The 1-Year Treasury constant maturity rate also decreased from 5.07 percent over the past year to 4.96 percent. Again, for the most part, these current yields are lower than corresponding yields that existed during the early nineties (as can be seen on Schedule WAR-8).

Q. What is the current outlook for interest rates, inflation, and the economy?

A. On May 9, 2007, the Federal Reserve decided not to increase or decrease the federal funds rate for the seventh straight FOMC meeting and left the key rate unchanged at 5.25 percent. According to an article[21] that appeared in the May 10, 2007 online edition of The Wall Street Journal, the Fed's action was based on some recent weakening of the economy. According to the Fed's statement that was released after the decision was made to sit pat on rates, the members of the FOMC believed that moderate economic growth was the likeliest scenario in the coming months. The statement also noted that the members of the FOMC expected somewhat elevated core inflation rates, which exclude volatile food and energy prices, to come down. The article also stated that the

[21] Ip, Greg, "Inflation Risk Keeps Fed on Alert," The Wall Street Journal, May 10, 2007.

financial markets still expect a rate cut later this year. In another article[22] that appeared at the time of this writing, The Wall Street Journal's Brian Blackstone quoted Chairman Bernanke as saying that "despite an 'ongoing' drag from the housing sector, the U.S. economy should expand at a moderate pace near its underlying potential in coming months as other factors limiting growth reverse." Chairman Bernanke also alluded, in prepared remarks to be delivered to the International Monetary Conference in Cape Town South Africa, to recent favorable readings on core inflation, citing the "gradual ebbing" that has been seen. Mr. Blackstone also noted that "amid signs of economic recovery and a deceleration in inflation, the Fed is expected to keep the key federal-funds rate at 5.25 percent throughout much of 2007 and perhaps even into 2008."

The recent views of Value Line analysts, who anticipate lower rates of inflation in the coming months, support the aforementioned outlook for stable rates. In their Economic and Stock Market Commentary that appeared in the February 2, 2007 edition of Value Line's Selection and Opinion publication, Value Line's analyst's stated the following:

> "Inflation is likely to start trending lower over the next few quarters, in part because the modest rate of GDP growth should cap the the increases in demand for labor and raw materials. Moreover, recent declines in oil prices will keep costs down for products that are oil-based and for companies that are heavy users of electricity."

[22] Blackstone, Brian, "Bernanke Sees Moderate Growth Despite Continued Housing Drag," The Wall Street Journal, June 5, 2007.

On March 23, 2007 Value Line's analysts had this to say:

> "Housing remains one of the wild cards in the economic situation. Recent months have seen this market weaken further, as slumping demand and higher monthly payments (for those with mortgages where the rates are now rising) have forced prices downward in a number of regions of the country. Should the recent gains in personal income and the brighter employment outlook help to gradually lessen the housing pressures, as we suspect, this sector should see its long decline moderate in the next few quarters.

Value Line's analysts stated the following in the June 8, 2007 Selection & Opinion publication:

> "It may be touch and go as to whether or not the Federal Reserve will reduce interest rates in the months to come. We think the Fed will carefully weigh the latest data from the housing and industrial fronts to gauge whether the economy can move forward, at even 2.0% - 2.5%, in the absence of lower interest rates. Should the Fed conclude that a rate reduction is needed, it may then try to determine whether or not inflation is low enough to justify such a cut. We think the Fed will end up voting for one to three rate reductions over the next year or so, on the expectation that inflation will slow modestly.

Q. How has the current economic environment of lower interest rates affected the electric utility industry as a whole?

A. Value Line analyst Nils C. Van Liew took note of the current environment of low interest rates recently. In Value Line's Electric Utility (East) Industry update dated March 2, 2007, Mr. Van Liew had this to say:

> "Several factors are, no doubt, driving the electric utilities' strong share - price performance. Perhaps most important is a benign interest-rate environment. Utilities frequently tap the credit markets to fund their operations. (Low interest rates mean they can cost-effectively build new power plants and maintain existing ones.) 'Cheap money' also tends to drive economic expansion, thereby increasing electricity demand. That said, interest rates should remain relatively low, though the likelihood that the Federal Reserve eases (monetary) policy is small, given persistent inflation concerns."

Q. What are the current dividend yields of electric utility stocks followed by Value Line?

A. In the May 11, 2007 Electric Utility (West) Industry update, Value Line analyst Paul E. Debbas, CFA, observed that following the continuing rise in electric utility stock prices (which have 52-week - or even all-time highs – as of late), the average yield of the electric utility stocks followed by Value Line has fallen to a historically low 3.20 percent. Mr. Debbas went on to note that by contrast, the average yield on electric stocks was over 5.00 percent as recently as 1999. According to Mr. Debbas, electric utility stocks hold a lot of appeal to investors seeking dividend income when returns on cash are very low. He also made note of the fact that the demand for electric utility stocks increased as a result of the 2003 change in the treatment of dividends.

Mr. Debbas' remarks were echoed by Value Line analyst Arthur H. Medalie. In his March 30, 2007 update on the Electric Utility (Central) Industry, Mr. Medalie stated that the average dividend yield for the electric utility industry is about double that of all dividend-paying stocks followed by Value Line. Mr. Medalie opined that conservative investors might want to consider electric utility companies, engaged in basic utility operations, which have strong finances and reasonable dividend growth prospects as an investment opportunity.

...

Q. How does the 3.20 percent average yield on electric utility stocks noted above compare with the average dividend yield of your sample electric utility companies?

A. As can be seen in Schedule WAR-3, my sample electric utility companies have an average dividend yield of 3.95 percent which is 75 basis points higher than the 3.20 percent average yield on electric utility stocks reported by Value Line's Mr. Debbas.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.30 percent cost of equity capital that you have estimated is reasonable for UNS?

A. I believe that my recommended 9.30 percent cost of equity will provide UNS with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards), a rebound in growth in new housing construction (attributed to historically low interest rates), and a low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed UNS' testimony on the Company-proposed costs of long and short-term debt?

A. Yes, I have reviewed the testimony prepared by Mr. Grant.

Q. Do you agree with Mr. Grant's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at his final cost of long-term debt figure of 8.22 percent?

A. Yes. I should also note that the financing application (Docket No. E-04204A-06-0493) referenced in Company witness Grant's direct testimony was approved by the Commission in Decision No. 69395, dated March 22, 2007.

Q. What are your recommended costs of long and short-term debt?

A. I am recommending the Company-proposed cost of long-tem debt of 8.22 percent and the Company-proposed cost of short-term debt of 6.36 percent.

CAPITAL STRUCTURE

Q. Have you reviewed UNS' testimony regarding the Company's proposed capital structure?

A. Yes, I have reviewed the direct testimony of Company witness Grant, who testified on UNS' proposed capital structure.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 3.97 percent short-term debt, 47.18 percent long-term debt and 48.85 percent common equity.

Q. What capital structure are you proposing for UNS?

A. I am recommending the same capital structure being proposed by UNS.

Q. Is the capital structure proposed by UNS in line with industry averages?

A. Yes. As can be seen in Schedule WAR-9, the capital structure proposed by UNS is just slightly higher in equity than the average capital structure of the electric utility companies included in my sample.

Q. In terms of risk, how does your recommended capital structure compare to the electric utility companies in your sample?

A. The electric utility companies in my sample would be considered as having a slightly higher level of financial risk (i.e. the risk associated with debt repayment) because of their slightly higher levels of debt. The additional financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived in my DCF analysis is applicable to companies that are slightly more leveraged and, theoretically speaking, slightly more risky than a utility with a level of debt similar to UNS'. In the case of a publicly traded company, such as those included in my proxy, a company with UNS' level of debt would be perceived as having a slightly lower level of financial risk and would therefore also have a slightly lower expected return on common equity. Based on the aforementioned facts I have decided not to make any upward or downward adjustments to my recommended cost of equity capital for UNS.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. The Company has proposed a weighted cost of capital of 9.89 percent. This composite figure is the result of a weighted average of UNS' proposed 6.36 percent cost of short-term debt, 8.22 percent cost of long-term debt and 11.80 percent cost of common equity. The Company-proposed 9.89 percent weighted cost of capital is 122 basis points higher than the 8.67 percent weighted cost that I am recommending, which is the weighted cost of my recommended 6.36 percent cost of short-term debt, 8.22 percent cost of long-term debt and 9.30 percent cost of common equity.

COMMENTS ON UNS' COST OF EQUITY CAPITAL TESTIMONY

Q. Have you studied the methodology that Company witness Grant used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Mr. Grant use to arrive at his cost of common equity for UNS?

A. Mr. Grant used a DCF methodology and a CAPM methodology to estimate UNS' cost of common equity.

Q. Can you provide a comparison of the results derived from Mr. Grant's models and yours?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Mr. Grant conducted his?

A. Yes, Mr. Grant relied on the results of a multi-stage DCF model, using the proxy of eight electric utility companies that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on.

Q. Do you agree with Mr. Grant's rationale for not relying on the single-stage DCF model?

A. No. The long-term growth rate that Mr. Grant uses in the second stage of his multi-stage DCF model is a 6.50 percent figure that falls within a range bounded on the upper side by investor expectations of the electric utility industry as a whole (which also falls within the range of analysts growth projections of his sample companies), and on the lower side by a 6.00 percent long-term projection of inflation-adjusted GDP, which is an inflation adjusted-projection of the growth rate of the entire U.S. economy. The use of such a growth estimate assumes that the long-term growth rate for the electric-utilities in his sample will be a combination of analysts' long-term growth rate projections and the growth rate of all goods and services produced by labor and property in the U.S. A good argument can be made that more emphasis should be placed on the near term component of Mr. Grant's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Mr. Grant?

A. Primarily because the growth rate component that I estimated for my single-stage model already takes into consideration long-term growth rate projections that are specific to the electric utilities included in my proxy.

Q. What is the difference between Mr. Grant's DCF estimate and your DCF estimate?

A. Mr. Grant's 10.35 percent median DCF estimate, derived from his multi-stage model, is 246 basis points higher than 7.89 percent cost of common equity derived from my constant growth, or single-stage DCF model which is a mean average of the estimates of the eight electric utility companies in my proxy.

Q. Does Mr. Grant provide an estimate that is based on the single-stage model that you employed?

A. Not directly, however the exhibits contained in his testimony contain inputs and estimates used in his multi-stage model that can also be used in the single-stage model. Using the inputs and estimates that appear in Mr. Grant's exhibits, a single-stage model would produce a cost of common equity estimate of 7.92 percent which is just 3 basis points higher than my DCF estimate of 7.89 percent.

Q. Have there been any changes in closing stock prices since Mr. Grant filed his direct testimony?

A. Yes. As Value Line's analysts noted in their recent updates on the electric utility industry, stock prices for electric utilities have been on the rise. The stock prices for the electric utility companies used in our proxies have increased since Mr. Grant filed his direct testimony, thus producing lower dividend yields. The difference between the average closing stock prices used in my analysis and Mr. Grant's analysis are as follows:

	Rigsby	Grant	Difference
CHG	$47.83	$49.73	- $1.90
CNL	$27.75	$25.14	$2.16
HE	$25.40	$27.10	- $1.70
MGEE	$35.39	$32.99	$2.40
NU	$31.84	$23.09	$8.75
NST	$35.95	$32.82	$3.13
PSD	$25.83	$22.44	$3.39
UIL	$34.31	$37.13	- $2.82

The differences in our respective dividend yields are as follows:

	Rigsby	Grant	Difference
CHG	4.52%	4.35%	0.49%
CNL	3.24%	3.58%	- 0.34%
HE	4.88%	4.58%	0.30%
MGEE	3.93%	4.28%	- 0.35%
NU	2.51%	3.30%	- 0.79%
NST	3.62%	3.87%	- 0.25%
PSD	3.87%	4.46%	- 0.59%
UIL	5.04%	4.66%	0.38%

When Mr. Grant's first year dividend estimates (i.e. the D_1 component of the DCF model) are divided by my more recent closing stock prices (i.e. the P_0 component of the DCF model) the resulting average dividend yield is 3.97 percent, which is only slightly higher than my 3.95 percent result exhibited in schedule WAR-3. The addition of a mean average of Mr. Grant's lower 5-year growth (i.e. the "g" component of the DCF model) estimate of 3.73 percent for his sample electric utility companies produces a single-stage estimate of 7.70 percent, which is 19 basis points lower than my 7.89 percent single-stage model estimate.

Based on this information it is fair to say that a single stage model using updated stock prices, while holding Mr. Grant's other DCF component estimates constant, would produce a lower single-stage DCF estimate than the one that I have calculated.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Mr. Grant conducted his?

A. The main difference between Mr. Grant's CAPM analysis and mine is that he relied solely on an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2005 as the proxy for the market rate of return (i.e. r_m) in order to arrive at his market risk premium (i.e. $r_m - r_f$) in his CAPM model.

Q. What financial instrument did Mr. Grant use as a proxy for the risk free (i.e. r_f) rate in his CAPM model?

A. Mr. Grant used the yield to maturity on a 20-year U.S. Treasury bond, which was 4.84 percent as of September 29, 2006.

Q. What is the current yield on a 20-year U.S. Treasury bond?

A. As of June 8, 2007 the yield on a 20-year U.S. Treasury bond had increased to 5.21 percent.

Q. Did Mr. Grant use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However the average of Value Line's beta's for the electric utility companies in our samples proxies have increased since Mr. Grant filed his direct testimony. The mean average of the Value Line betas used by Mr. Grant is 0.86 as opposed to my average beta of 0.90.

Q. What would Mr. Grant's expected return be if his CAPM model (using an arithmetic mean) were updated to include the aforementioned changes in the average beta coefficient and the 20-year Treasury bond yield?

A. An update of Mr. Grant's CAPM model using an average beta of 0.90 and a risk free rate of 5.21 percent would produce an expected return of 11.60 percent, which is 4 basis points higher than my 11.56 percent result using an arithmetic mean.

Q. What is the difference between Mr. Grant's CAPM estimates and your CAPM estimates?

A. Mr. Grant's 10.70 percent median CAPM estimate using an arithmetic mean for the market risk premium (including Cleco Corporation) is 86 basis points lower than the 11.56 percent cost of common equity derived from my arithmetic mean CAPM analysis which is a mean average of the eight electric utility companies in my proxy. Mr. Grant's CAPM 10.70 percent median is 85 basis points higher than the 9.85 percent cost of common equity derived from my geometric mean CAPM analysis. In making his recommended high and low end ranges, displayed on page 19 of his direct testimony, Mr. Grant excluded the results of Cleco Corporation because of its higher beta coefficient that equaled 1.25 at the time of his study and 1.30 at the time of my study (the exclusion of Cleco Corporation results in a median of 10.50 percent).

Final Cost of Equity Estimate

Q. How did Mr. Grant arrive at his final estimate of 11.80 percent for UNS?

A. Mr. Grant's final 11.80 percent recommendation is the 11.20 percent high end of his range of DCF and CAPM estimates plus an upward adjustment of 60 basis points. The 60 basis point upward adjustment is Mr. Grant's observed difference between utility bond yields with investment grade Triple-B credit ratings (Baa or BBB) and speculative Double-B credit ratings (Ba or BB). Mr. Grant's upward adjustment of 60 basis points is based on his belief that UNS is riskier as a result of a number of factors including the Company's size, a speculative-grade credit rating associated with long-term notes issued in 2003, high customer growth rate, and the need to procure a new power supply in 2008.

Q. Do you believe that UNS should be awarded a higher return on equity based on the factors cited by Mr. Grant?

A. No. The Commission in prior cases has rejected many of the factors cited by Mr. Grant. This includes such issues such as company size and customer growth projections. In regard to UNS' need to procure a new power supply in 2008, RUCO witness Marylee Diaz Cortez, CPA, is recommending modifications to the Company's purchased power and fuel adjustor mechanism that will, if adopted by the Commission, mitigate the risks associated with this future event and improve UNS' overall financial condition.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Grant or any other witness for UNS constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNS?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0403	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase

ATTACHMENTS

ATTACHMENT A

All of the major utilities in the central United States are reviewed in this Issue. Those serving the western region may be found in Issue 11. The eastern companies are covered in Issue 1.

INDUSTRY TIMELINESS: 71 (of 96)

The pressure of an ever-growing demand for energy is reducing reserve margins and leading to the need for more generation. Power usage in the U.S. is increasing at an annual rate of 2%. This, coupled with low interest rates, is inducing utilities to increase spending on new plants. Construction of fossil-fueled facilities accounts for most of the new capacity. But dependence on foreign oil, atmospheric pollution created by coal-fired units, and the high cost of natural gas have stimulated interest in renewable energy by state and federal regulatory bodies and by utilities themselves.

Regulatory Requirements

At the turn of the century, wind, geothermal, solar, biomass, and miscellaneous renewables accounted for only a low single-digit percentage of power output. A turnaround began as state and federal officials and company managements came to realize their benefits. Jeff Bingaman, chairman of the Senate Energy and Natural Resources Committee, recently announced that he will introduce a bill requiring that 15% of the nation's power supply come from renewable sources by 2020. On the state level, the Arizona commission requires renewables in its jurisdiction to represent 15% of total power output by 2025. Legislators in Wisconsin have introduced a more modest bill calling for 10% from renewables by 2015. In Michigan, however, a bill providing for 10% of power from renewable sources and granting tax credits for wind turbines and windmills was vetoed by the governor, on the grounds that the state could not afford to grant tax credits because of the loss of jobs in the automotive industry. At this time, renewable portfolio requirements are in place in 20 states.

A New Fuel Emerges

In 2006, Edison International led the nation in delivery of energy from geothermal, wind, biomass, and solar power. It generated sufficient electricity from this program to serve 1.8 million homes for an entire year. It hopes to have long-term contracts with companies developing these projects to furnish 20% or more of its customer needs by 2010. PG&E, for its part, has agreed to buy 500 megawatts (mw) of solar power, 300 mw of wind-driven energy, and lesser amounts of biomass and geothermal generation. With these purchases, renewables will account for 20% of the company's output in the next few years. FPL Group is not far behind. It invested $1 billion last year in wind-driven power in 15 states, helped by federal tax credits of 1.8¢ a kilowatt-hour that make this source competitive with fossil-fuel generation. The credits, which were due to expire at the end of 2007, were extended for an additional year, and all wind mills already operating at that time will continue to benefit from tax credits when the law elapses. FPL Group also has a 310-mw investment in solar power, but has no plans to expand in this area because of the absence of tax credits. In the central region, *TXU* plans to boost its wind power capacity to 1,500 mw, making it the largest source of this power in the country. *Western Resources* has issued a request for 500 mw of wind and other renewable sources of energy, which it will either lease or buy outright. *Alliant Energy* has purchased development rights to a proposed 80- to 100-mw wind farm. It is also studying the burning of paper byproducts, agricultural waste, and animal and food waste. *Entergy* has issued a request for proposals for 40,000 megawatt hours of renewable energy to be used as a pilot to help determine interest in acquiring alternative power sources.

A report by consulting firm Wood Mackenzie stated that if renewables accounted for 15% of national power output, natural gas and wholesale power costs would be driven down. Over the next 20 years, that could lead to savings of as much as $240 billion, more than outweighing the high capital cost of building renewable capacity. Though the addition of renewables would not reduce greenhouse emissions below present levels, it would slow their growth. Despite these pluses, challenges remain to renewable power projects, because of uncertainty about tax incentives and concerns related to siting of new facilities.

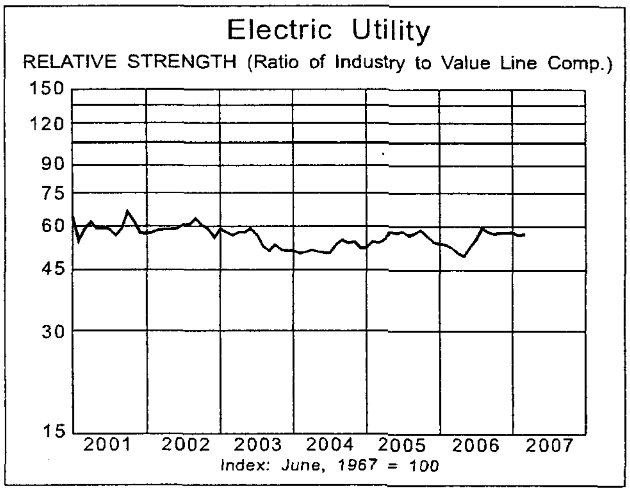
Investment Advice

The Electric Utility Industry is untimely, but it may be of interest because its average dividend yield is about double that of all dividend-paying stocks followed by *Value Line*. Conservative investors might consider those companies with strong finances, reasonable dividend-growth prospects, and those engaged in basic utility operations.

Arthur H. Medalie

Composite Statistics: Electric Utility Industry

2003	2004	2005	2006	2007	2008		10-12
289.2	299.3	336.7	354.1	*380*	*400*	Revenues ($bill)	*480*
19.3	20.3	24.0	25.7	*29.0*	*32.0*	Net Profit ($bill)	*39.0*
30.3%	30.3%	29.5%	29.7%	*33.5%*	*34.5%*	Income Tax Rate	*34.5%*
4.3%	3.5%	3.5%	3.3%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
59.1%	57.2%	55.7%	55.0%	*52.5%*	*52.0%*	Long-Term Debt Ratio	*49.5%*
39.2%	41.7%	43.1%	43.9%	*46.5%*	*47.0%*	Common Equity Ratio	*49.5%*
439.5	441.8	446.1	473.9	*510*	*520*	Total Capital ($bill)	*560*
443.9	453.6	469.3	496.6	*535*	*560*	Net Plant ($bill)	*600*
6.4%	6.5%	7.2%	7.3%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
10.7%	10.8%	12.1%	12.2%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
10.9%	10.9%	12.3%	12.4%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
4.8%	4.7%	5.5%	5.5%	*5.0%*	*5.0%*	Retained to Com Eq	*5.0%*
57%	57%	56%	56%	*63%*	*61%*	All Div'ds to Net Prof	*59%*
15.2	16.0	15.8	15.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.80	.85	.85	.86			Relative P/E Ratio	*.90*
3.7%	3.5%	3.5%	3.5%			Avg Ann'l Div'd Yield	*4.4%*



All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

Since some parts of the country are facing a shortage of generating capacity in the coming years, some utilities have reentered the construction cycle. We examine the advantages and disadvantages of each kind of generation.

Electric utility stocks performed well in 2006, and the momentum has continued into 2007. The average yield is at a historical low.

Building Generating Capacity

A few years ago, many parts of the country were awash in generating capacity after numerous plants (virtually all of them gas-fired) were built in the late 1990s and early 2000s. Most of these facilities were built by independent power producers (IPPs) or nonregulated siblings of electric utilities. After the collapse of the power markets in 2001 and 2002, along with the spike in natural gas prices, some IPPs filed for bankruptcy protection, and little capacity was built. Some plants were even discontinued after construction had begun.

Since a few years have passed with an increase in demand for electricity but without much new generating capacity, some utilities are concerned about a looming power shortage. So, they have begun to build power plants or have facilities on the drawing board. Some also want to build capacity in order to reduce their dependency on purchased power, the cost of which has become very volatile at times. (*Puget Energy* and *Sierra Pacific Resources* are two such companies.) This raises the question: What kind of plants should be built?

Gas-fired plants are easier and less costly to build than coal-fired facilities, and are also cleaner, but the price of natural gas is volatile and supplies in North America are becoming tighter. (There is actually plenty of gas, but much of it is off-limits to developers due to environmental concerns.) Coal is abundant, but comes with environmental issues. Some utilities are studying the possibility of building nuclear plants. Nuclear facilities do not produce any greenhouse gases, but they are very expensive and difficult to build. Moreover, a permanent repository for nuclear waste has not yet been

INDUSTRY TIMELINESS: 80 (of 96)

established. Even if the regulatory process toward building a nuclear unit were to begin today, the plant wouldn't come on line before the middle of the next decade. Wind power is appealing to a lot of utilities, especially because 23 states require that a certain proportion of power come from renewable sources by a specified year. But the capital costs of building wind projects are high, the facilities are typically built in remote areas that require a lot of transmission spending, and wind power isn't economically viable without production tax credits.

There are many examples of the varied approaches that utilities are taking to add capacity. TXU backed off its plans to build coal-fired plants after much criticism, so the company is now considering nuclear power. Wisconsin Energy is building two coal-fired units and two gas-fired units (one of which is already on line.) The plants will be owned by a nonregulated subsidiary, which will lease them to its utility sibling. In recent years, *Puget Energy's* utility subsidiary has built two wind projects and acquired two gas-fired plants. *Sierra Pacific Resources'* two utilities have built or acquired gas-fired plants and have a big coal project planned. Some utilities in Missouri have begun construction of a coal-fired unit. Another group is also studying coal gasification plants, notably American Electric Power, Duke Energy, Southern Company, and TECO Energy. These plants are very expensive, however.

Investment Advice

Following the continuing rise in most electric utility stocks, the average yield of the group has fallen to a historically low 3.2%. (By contrast, it was over 5% as recently as 1999.) These stocks hold a lot of appeal to investors seeking dividend income when returns on cash are very low. The 2003 change in the tax treatment of dividends has stimulated the demand for these equities. Dividend growth (and, in the case of CMS Energy, a dividend restoration) has been another selling point of electric utility issues. Many of these stocks have reached 52-week highs—or even all-time highs—of late. We are concerned about the lofty valuation of these equities and thus advise investors to proceed cautiously.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2003	2004	2005	2006	2007	2008		10-12
289.2	299.3	336.7	336.0	**380**	**400**	Revenues ($bill)	**480**
19.3	20.3	24.0	26.8	**29.0**	**32.0**	Net Profit ($bill)	**39.0**
30.3%	30.3%	29.5%	32.0%	**33.5%**	**34.5%**	Income Tax Rate	**34.5%**
4.3%	3.5%	3.5%	4.1%	**4.0%**	**5.0%**	AFUDC % to Net Profit	**3.0%**
59.1%	57.2%	55.7%	53.3%	**52.5%**	**52.0%**	Long-Term Debt Ratio	**49.5%**
39.2%	41.7%	43.1%	45.5%	**46.5%**	**47.0%**	Common Equity Ratio	**49.5%**
439.5	441.8	446.1	448.7	**510**	**520**	Total Capital ($bill)	**560**
443.9	453.6	469.3	481.0	**535**	**560**	Net Plant ($bill)	**600**
6.4%	6.5%	7.2%	7.7%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
10.7%	10.8%	12.1%	12.8%	**11.0%**	**11.0%**	Return on Shr. Equity	**11.0%**
10.9%	10.9%	12.3%	13.0%	**11.0%**	**11.0%**	Return on Com Equity	**11.0%**
4.8%	4.7%	5.5%	6.2%	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
57%	57%	56%	53%	**63%**	**61%**	All Div'ds to Net Prof	**59%**
13.5	15.2	16.0	15.2	*Bold figures are*		Avg Ann'l P/E Ratio	**13.5**
.77	.80	.85	.82	*Value Line*		Relative P/E Ratio	**.90**
4.1%	3.7%	3.5%	3.5%	*estimates*		Avg Ann'l Div'd Yield	**4.4%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2003	2004	2005
% Change Retail Sales (kwh)	+1.3	+.3	+5.4
Average Indust. Use (mwh)	1662	1384	1497
Avg. Indust. Revs. per kwh (¢)	5.07	5.25	5.78
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.9	+1.6	+1.2
Fixed Charge Coverage (%)	207	230	260

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

All of the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western companies are covered in Issue 11.

As measured by share-price performance, investor sentiment towards the electric utilities, including those serving the eastern seaboard, remains high. During the three-month stretch since our last review, a majority of the group (19 of 22) has boasted share-price gains, with 11 besting the 5% advance by the S&P 500 Index. *Central Vermont Public Service* tops the list (+40%). Recent merger activity in northern New England has fueled speculation that the tiny Rutland, VT-based utility (market capitalization: $375 million) is a buyout candidate. By contrast, *UIL Holdings*, parent of Connecticut-based utility United Illuminating, was the laggard of the group. Its shares are down 15%.

Rich Valuations

The valuations with which electric utilities are currently being accorded are increasingly a topic for discussion. We still think that there is some "frothiness" in the sector and that, in general, investors can expect fairly muted total returns (capital appreciation, plus dividends) out to 2010-2012.

Price-to-earnings multiples certainly suggest that many of the names here are richly valued. Half of the eastern utility group's shares are trading at a 20%-plus premium to their median price-to-earnings ratio. The (price-to-earnings) discount at which the group typically trades, relative to the *Value Line Composite Index*, has also narrowed substantially. That said,we are not dismissing the idea that a more-benign regulatory environment may result in higher sustainable earnings growth and that utilities, therefore, deserve more-positive valuations.

Transmission Corridors

The proposed establishment of national interest electric transmission corridors (NIETCs), including one covering parts of six Mid-Atlantic States (NY, NJ, MD, VA, WVA, PA) and the District of Columbia, is being hotly debated. Should the Department of Energy sign off on the designation of these corridors, the Federal Energy Regulatory Commission will have increased power to ease the often languid state and local approval process for new interstate transmission investment.

INDUSTRY TIMELINESS: 65 (of 96)

Economic incentives, including fairly attractive returns on equity rates, have already spurred tranmission investment. The establishment of these corridors should be another log on the proverbial fire. As mandated by the Energy Policy Act of 2005, these initiatives and others will help improve reliability of the nation's power grid. It is also argued that the corridors will promote the development of renewable energy sources, since these long-range conduits can connect typically rural wind farms and high-energy-demand population centers.

New power transmission projects could ultimately boost the earnings of regional service providers. Utilities with large-scale transmission proposals include *Allegheny Energy*, *American Electric Power*, *Dominion Resources*, and *PEPCO Holdings*. That said, there is pretty fierce opposition to these NIETCs, not the least of which is the contention that they usurp states' rights.

Nuclear Power

Constellation Energy, *Central Vermont Public Service*, and other utilities that rely heavily on nuclear power for their power output have been standouts of late, in terms of share-price performance. That is not very surprising. More and more, nuclear power is being touted as low cost, low emission, and, "energy independence" enabling. On the downside, nuclear reactors are high profile targets for terrorists. What to do with spent fuel remains a question as well.

Investment Considerations

Among the positive attributes that investors should look for when seeking an attractive utility are an economically healthy local service territory (such as those in the Southeast); a large customer base; good management-regulator relations; access to low-cost power generation (coal, nuclear); and ample fixed-charge coverage.

Nils C. Van Liew

Composite Statistics: Electric Utility Industry

2003	2004	2005	2006	2007	2008		10-12
311.7	321.8	353.4	347.7	*375*	*390*	Revenues ($bill)	*470*
20.2	21.7	25.6	27.5	*32.0*	*34.0*	Net Profit ($bill)	*40.0*
30.7%	30.4%	29.6%	32.1%	*33.0%*	*33.0%*	Income Tax Rate	*33.0%*
4.8%	3.7%	3.5%	4.1%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*3.0%*
59.1%	56.7%	55.1%	53.4%	*52.0%*	*51.5%*	Long-Term Debt Ratio	*49.5%*
39.3%	42.2%	43.8%	46.6%	*47.0%*	*47.5%*	Common Equity Ratio	*49.5%*
474.0	475.3	477.1	462.6	*480*	*500*	Total Capital ($bill)	*560*
478.9	487.1	498.5	449.6	*470*	*490*	Net Plant ($bill)	*550*
6.2%	6.5%	7.2%	7.7%	*8.0%*	*8.0%*	Return on Total Cap'l	*7.0%*
10.4%	10.5%	12.0%	12.7%	*14.0%*	*14.0%*	Return on Shr. Equity	*13.5%*
10.5%	10.6%	12.1%	12.9%	*14.2%*	*14.2%*	Return on Com Equity	*13.5%*
4.4%	4.5%	5.3%	6.2%	*6.0%*	*6.0%*	Retained to Com Eq	*5.0%*
60%	59%	57%	57%	*57%*	*57%*	All Div'ds to Net Prof	*59%*
13.8	15.3	16.0	15.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.79	.81	.85	.83			Relative P/E Ratio	*.90*
4.3%	3.8%	3.5%	3.4%			Avg Ann'l Div'd Yield	*4.4%*

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2003	2004	2005
% Change Retail Sales (kwh)	+1.3	+.3	+5.4
Average Indust. Use (mwh)	1662	1384	1497
Avg. Indust. Revs. per kwh (¢)	5.07	5.25	5.78
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.9	+1.6	+1.2
Fixed Charge Coverage (%)	207	230	260

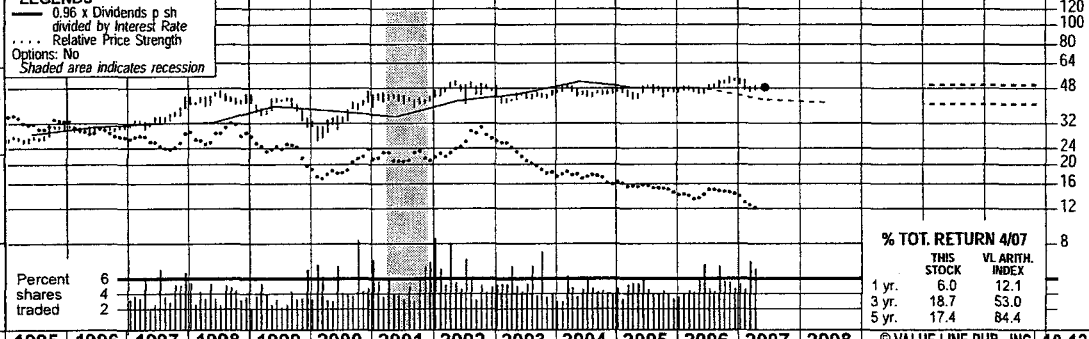
Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

CH ENERGY GROUP NYSE-CHG

RECENT PRICE **48.55** | P/E RATIO **18.0** (Trailing: 17.5 / Median: 15.0) | RELATIVE P/E RATIO **0.94** | DIV'D YLD **4.4%** | VALUE LINE

TIMELINESS 4 Lowered 3/23/07
SAFETY 1 Raised 12/7/01
TECHNICAL 4 Raised 6/1/07
BETA .85 (1.00 = Market)

High:	31.5	43.9	47.1	45.0	46.3	45.9	52.4	49.7	49.6	50.2	54.9	53.8
Low:	28.8	29.8	38.9	30.6	26.1	38.3	39.9	40.2	43.1	42.1	44.6	45.9



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+5%)	5%
Low	40	(-20%)	Nil

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	5	0	0	1	1
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	49	43	55
to Sell	42	37	36
Hld's(000)	7829	8212	7948

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	6.0	12.1
3 yr.	18.7	53.0
5 yr.	17.4	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
31.38	32.66	30.52	29.91	29.28	29.28	30.11	29.86	30.95	45.83	44.52	43.29	51.18	50.22	61.70	63.03	66.95	72.00	Revenues per sh	88.75
4.99	5.22	5.23	5.25	5.33	5.69	5.80	5.83	5.92	6.49	5.50	4.18	5.02	4.89	5.11	4.83	5.20	5.45	"Cash Flow" per sh	6.25
2.40	2.55	2.68	2.68	2.74	2.99	2.97	2.90	2.88	3.05	3.11	2.12	2.78	2.69	2.81	2.56	2.70	2.85	Earnings per sh A	3.25
1.90	1.98	2.05	2.08	2.10	2.12	2.14	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	Div'd Decl'd per sh B ■ †	2.26
4.44	3.81	3.13	3.37	2.87	2.84	2.54	2.71	2.76	3.58	4.14	4.50	3.79	3.98	4.05	4.76	5.85	5.40	Cap'l Spending per sh	5.25
22.84	23.60	24.65	25.33	25.96	26.87	27.61	28.00	28.73	29.38	30.33	30.31	30.80	31.31	31.97	32.54	33.05	33.75	Book Value per sh C	35.75
15.77	16.03	16.95	17.24	17.50	17.56	17.28	16.86	16.86	16.36	16.36	16.06	15.76	15.76	15.76	15.76	15.76	15.76	Common Shs Outst'g D	15.00
10.7	11.2	12.2	10.0	10.2	10.1	11.5	14.6	13.5	11.4	13.6	22.6	15.7	17.2	16.5	19.1	Bold figures are	Value Line	Avg Ann'l P/E Ratio	14.0
.68	.68	.72	.66	.68	.63	.66	.76	.77	.74	.70	1.23	.90	.91	.88	1.03	estimates		Relative P/E Ratio	.95
7.4%	6.9%	6.3%	7.8%	7.5%	7.0%	6.3%	5.1%	5.6%	6.2%	5.1%	4.5%	4.9%	4.7%	4.7%	4.4%			Avg Ann'l Div'd Yield	5.0%

CAPITAL STRUCTURE as of 3/31/07
Total Debt $413.9 mill. Due in 5 Yrs $87.0 mill.
LT Debt $370.9 mill. LT Interest $16.9 mill.
(LT interest earned: 4.9x)
Leases, Uncapitalized Annual rentals $3.1 mill.
Pension Assets-12/06 $359.6 mill. **Oblig.** $414.5 mill.
Pfd Stock $21.0 mill. **Pfd Div'd** $1.0 mill.
210,300 shs. 4½%-4.96% cum., $100 par, redeemable at $101-$107/sh.

Common Stock 15,762,000 shs.
as of 5/1/07
MARKET CAP: $775 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
520.3	503.5	521.9	749.9	728.4	695.5	806.7	791.5	972.5	993.4	1055	1135	Revenues ($mill)	1330
55.1	52.5	51.8	54.2	54.1	36.6	45.4	43.4	45.3	41.4	43.0	45.0	Net Profit ($mill)	48.0
32.3%	35.3%	35.8%	41.4%	--	36.6%	40.1%	41.9%	36.3%	36.3%	40.0%	40.0%	Income Tax Rate	40.0%
1.2%	1.7%	.8%	1.4%	1.4%	2.3%	1.6%	.9%	.9%	1.5%	1.0%	1.0%	AFUDC % to Net Profit	1.0%
40.4%	40.3%	38.3%	37.4%	28.1%	34.1%	35.5%	38.3%	39.6%	38.8%	42.5%	44.0%	Long-Term Debt Ratio	49.5%
53.3%	53.3%	55.3%	56.1%	64.6%	61.6%	61.8%	59.1%	58.0%	58.8%	55.5%	54.0%	Common Equity Ratio	48.5%
895.0	885.1	875.9	857.1	768.5	790.3	785.3	834.4	868.7	871.8	945	990	Total Capital ($mill)	1100
932.8	928.2	921.4	930.9	561.8	601.7	707.5	745.1	779.5	827.1	880	925	Net Plant ($mill)	1050
7.4%	7.2%	7.3%	7.7%	8.1%	5.4%	6.5%	5.9%	6.0%	5.7%	5.5%	5.5%	Return on Total Cap'l	5.5%
10.3%	9.9%	9.6%	10.1%	9.8%	7.0%	9.0%	8.4%	8.6%	7.7%	8.0%	8.0%	Return on Shr. Equity	8.5%
10.9%	10.4%	10.0%	10.6%	10.2%	7.1%	9.1%	8.6%	8.8%	7.9%	8.0%	8.5%	Return on Com Equity E	9.0%
3.1%	2.7%	2.5%	3.1%	3.1%	NMF	2.0%	1.7%	2.0%	1.2%	1.5%	2.0%	Retained to Com Eq	2.5%
73%	76%	77%	73%	71%	102%	78%	81%	77%	85%	82%	78%	All Div'ds to Net Prof	72%

ELECTRIC OPERATING STATISTICS

=	2004	2005	2006
% Change Retail Sales (KWH)	+2.1	+4.5	-4.2
Avg. Indust. Use (MWH)	1407	1407	1377
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1051	1204	1295
Peak Load, Summer (Mw)	1051	1204	1295
Annual Load Factor (%)	61.0	57.0	50.0
% Change Customers (avg.)	+1.0	+1.3	+.9
Fixed Charge Cov. (%)	374	408	328

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.0%	7.5%	7.5%
"Cash Flow"	-1.0%	-3.5%	4.0%
Earnings	-.5%	-2.5%	3.0%
Dividends	.5%	--	1.0%
Book Value	2.0%	1.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	263.0	165.3	161.9	201.3	791.5
2005	286.1	189.6	227.9	268.9	972.5
2006	317.2	213.9	239.8	222.5	993.4
2007	343.4	215	235	261.6	1055
2008	375	230	250	280	1135

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.46	.35	.28	.60	2.69
2005	1.29	.41	.36	.74	2.81
2006	1.16	.26	.55	.60	2.56
2007	1.37	.34	.34	.65	2.70
2008	1.40	.37	.38	.70	2.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.54	.54	.54	.54	2.16
2004	.54	.54	.54	.54	2.16
2005	.54	.54	.54	.54	2.16
2006	.54	.54	.54	.54	2.16
2007	.54	.54			

BUSINESS: CH Energy Group, Inc. is a holding company for Central Hudson Gas & Electric, which provides electricity and gas in the Mid-Hudson Valley region of New York State (79% of '06 income). Customers: 293,000 electric, 71,000 gas. Griffith Energy provides gas, oil, electricity, & propane to over 100,000 customers in Northeast (4% of '06 income). Investments were 17% of '06 income. Electric revenue breakdown, '06: residential, 51%; commercial, 32%; industrial, 7%; other, 10%. Generating sources, '06: hydro, 3%; purchased, 97%. Fuel costs: 66% of revenues. '06 reported depreciation rate (utility): 3.0%. Chairman, President & CEO: Steven V. Lant. Inc.: NY. Address: 284 South Ave., Poughkeepsie, NY 12601-4879. Tel.: 845-452-2000. Internet: www.chenergy.com.

We have raised our 2007 earnings estimate for CH Energy Group by $0.10 a share, to $2.70. This past winter, the utility's service territory was not hit with the severe storms that occurred in the first quarter of 2006. These more favorable weather conditions enabled first-quarter earnings to rise significantly. In addition, the price elasticity that was affecting electric and gas sales appears to be abating. On the nonregulated side, the Griffith Energy subsidiary is performing better, thanks to acquisitions (see below) and increased margins. Our earnings estimate is within CH Energy's targeted range of $2.55-$2.80 a share. We have boosted our 2008 forecast by $0.15 a share, to $2.85. The company has not yet provided guidance for next year.

CH Energy is growing through acquisitions. In 2006, Griffith Energy closed nine deals for a total of $3.6 million. So far in 2007, the acquisitions have been bigger: three for a total of $9.9 million. These purchases boosted Griffith's customer base by 17%, to over 100,000. In recent years, CH Energy has also made investments in an ethanol plant, a biomass-to-energy facility, and wind projects. The company has ample cash and borrowing capacity to fund acquisitions.

Finances are sound. Although the fixed-charge coverage declined in 2006, it remains well above the industry average. The common-equity ratio is high, too. CH Energy merits a Financial Strength Rating of A, and its stock is top-ranked for Safety.

CH Energy wants to resume dividend growth. The board of directors hasn't raised the dividend since the late 1990s. The current payout ratio is on the high side, so we expect no dividend increase this year or next. The company has set a goal of boosting the disbursement by 5% by 2011, which we think is achievable. We have adjusted our 3- to 5-year projections accordingly.

This stock is untimely, but its yield is more than one percentage point above the norm for the electric utility industry as a whole. Even though we have boosted our 2010-2012 dividend projections, however, total-return potential over that time is subpar.

Paul E. Debbas, CFA *June 1, 2007*

(A) Diluted earnings. Excl. nonrecurring gains: '92, 10¢; '02, 12¢; '06, 17¢; gain from discontinued operation: '02, 29¢. '05 & '06 earnings don't add to total due to rounding. Next earnings report due late July. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '06: $299.2 mill., $18.98/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '06: 10.6%; earned on avg. com. eq., '06: 8.0%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

CLECO CORPORATION NYSE-CNL

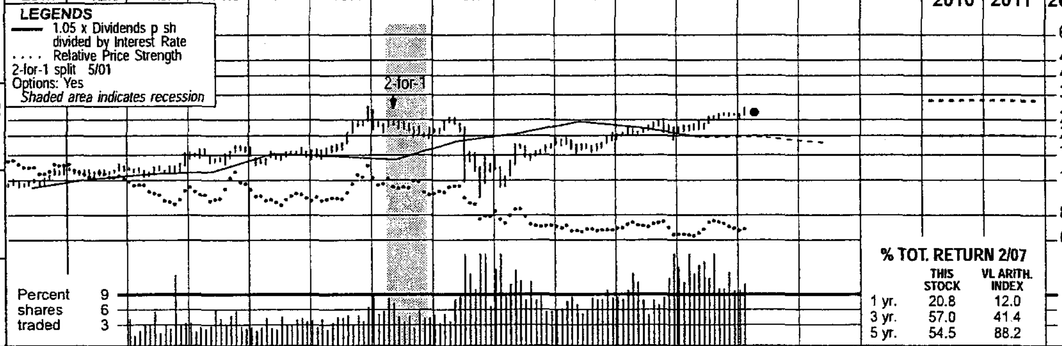
RECENT PRICE 26.15 | P/E RATIO 21.1 (Trailing: 19.2 Median: 13.0) | RELATIVE P/E RATIO 1.13 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 4 Raised 8/11/06
SAFETY 3 Lowered 1/3/03
TECHNICAL 4 Lowered 3/16/07
BETA 1.30 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	14.6	16.6	18.1	17.8	28.3	27.3	24.9	18.4	20.8	24.4	26.2	27.8
Low:	12.6	12.4	14.3	14.1	15.1	19.2	9.7	11.0	16.2	18.9	20.5	24.3

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.05 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/01
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-25%)	-2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	1	0
to Sell	0	0	0	0	0	0	0	3	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	77	109	90
to Sell	62	46	81
Hld's(000)	34731	41017	40413

Percent shares traded 9 6 3

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	20.8	12.0
3 yr.	57.0	41.4
5 yr.	54.5	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
7.58	7.88	8.54	8.48	8.79	9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	*17.25*	*18.20*	*19.15*	Revenues per sh	*23.50*
1.76	1.78	1.74	1.85	1.99	2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	*2.50*	*2.50*	*2.60*	"Cash Flow" per sh	*3.50*
.96	.97	.89	.96	1.04	1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	*1.25*	*1.30*	Earnings per sh A	*1.75*
.66	.69	.71	.73	.75	.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	*.90*	*.90*	Div'd Decl'd per sh B ■ †	*1.20*
1.23	1.44	1.15	1.24	1.29	1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	*5.50*	*8.80*	*6.15*	Cap'l Spending per sh	*1.75*
6.76	7.06	7.29	7.56	7.91	8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	*15.05*	*15.55*	*16.10*	Book Value per sh C	*18.00*
44.48	44.61	44.77	44.78	44.85	44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	*58.00*	*59.00*	*60.00*	Common Shs Outst'g D	*63.00*
10.7	12.5	14.3	12.1	11.6	11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.68	.76	.84	.79	.78	.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.94	*Value Line*		Relative P/E Ratio	*.95*
6.4%	5.7%	5.5%	6.2%	6.2%	5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $629.4 mill. **Due in 5 Yrs** $230.0 mill.
LT Debt $584.4 mill. **LT Interest** $38.0 mill.
Excludes $174.2 mill. off-balance-sheet financing.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $53.0 mill.
Pension Assets-12/05 $225.3 mill. **Oblig.** $256.2 mill.
Pfd Stock $21.0 mill. **Pfd Div'd** $1.8 mill.
Includes 210,175 shares 8.125%, each convertible into 9.6 common shares, callable at $100.8125.
Common Stock 57,488,574 shs.
as of 10/31/06
MARKET CAP: $1.5 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
456.2	515.2	768.2	820.0	1058.6	721.2	874.6	745.8	920.2	1000.7	*1075*	*1150*	Revenues ($mill)	*1475*
52.5	53.8	56.8	69.3	72.3	74.2	61.2	66.1	75.0	74.7	*75.0*	*80.0*	Net Profit ($mill)	*115*
34.6%	33.1%	32.4%	33.5%	34.7%	36.9%	37.2%	35.2%	39.2%	36.0%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
1.5%	3.2%	10.6%	12.1%	16.7%	12.6%	5.8%	7.5%	4.3%	*19.0%*	*40.0%*	*51.0%*	AFUDC % to Net Profit	*4.0%*
46.2%	43.6%	56.2%	57.9%	55.2%	60.0%	64.4%	44.5%	46.3%	*41.0%*	*45.5%*	*51.5%*	Long-Term Debt Ratio	*51.5%*
49.2%	51.9%	41.0%	39.7%	42.4%	38.2%	33.8%	53.1%	52.0%	*57.5%*	*53.5%*	*47.5%*	Common Equity Ratio	*48.0%*
792.1	786.2	1032.1	1139.2	1134.7	1448.7	1408.5	1011.6	1315.9	1513.7	*1725*	*2035*	Total Capital ($mill)	*2350*
1025.6	1089.8	1211.6	1232.8	1224.7	1566.2	1417.1	1060.0	1188.7	1304.9	*1755*	*2050*	Net Plant ($mill)	*2250*
8.1%	8.3%	6.9%	8.3%	8.6%	7.1%	6.7%	8.9%	7.1%	*6.0%*	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
12.3%	12.1%	12.5%	14.4%	14.2%	12.8%	12.2%	11.8%	10.6%	*8.5%*	*8.0%*	*8.0%*	Return on Shr. Equity	*10.0%*
12.9%	12.7%	12.9%	14.9%	14.6%	13.1%	12.5%	11.9%	10.7%	*8.5%*	*8.0%*	*8.0%*	Return on Com Equity E	*10.0%*
3.9%	3.8%	4.2%	6.5%	6.5%	5.6%	3.5%	3.9%	4.1%	*3.0%*	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
71%	71%	69%	57%	57%	58%	72%	68%	62%	*67%*	*73%*	*70%*	All Div'ds to Net Prof	*68%*

ELECTRIC OPERATING STATISTICS

	2003	2004	2005
% Change Retail Sales (KWH)	+1.5	+2.6	-.2
Avg. Indust. Use (MWH)	3806	4194	4245
Avg. Indust. Revs. per KWH (¢)	5.41	5.67	7.22
Capacity at Peak (Mw)	2216	2190	2030
Peak Load, Summer (Mw)	1990	1940	2014
Annual Load Factor (%)	58.2	60.0	57.2
% Change Customers (avg.)	+1.3	+1.8	+.8
Fixed Charge Cov. (%)	181	174	247

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '10-'12
Revenues	7.0%	2.0%	*4.5%*
"Cash Flow"	4.0%	2.5%	*3.5%*
Earnings	3.5%	1.0%	*4.0%*
Dividends	2.0%	2.0%	*4.0%*
Book Value	4.5%	4.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	166.6	166.3	229.4	183.5	745.8
2005	172.1	194.1	283.7	270.3	920.2
2006	223.4	251.0	294.1	232.2	1000.7
2007	*240*	*270*	*320*	*245*	*1075*
2008	*255*	*285*	*350*	*260*	*1150*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.26	.22	.56	.27	1.32
2005	.18	.40	.82	.03	1.42
2006	.23	.44	.50	.19	1.36
2007	*.20*	*.35*	*.50*	*.20*	*1.25*
2008	*.20*	*.37*	*.53*	*.20*	*1.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.225	.225	.225	.225	.90
2004	.225	.225	.225	.225	.90
2005	.225	.225	.225	.225	.90
2006	.225	.225	.225	.225	.90
2007	.225				

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 267,000 customers in central Louisiana. *Through subsidiaries, has about 1,350 megawatts of wholesale capacity.* Electric revenue breakdown, '05: residential, 48%; commercial, 22%; industrial, 17%; other, 13%. Largest industrial customers are paper mills and other wood-product industries. Generating sources, '05: coal & lignite, 34%; gas & oil, 17%; purchased, 49%. Fuel costs: 62% of revenues. '05 reported deprec. rate (utility): 3.3%. Has 1,150 employees. Chairman: J. Patrick Garrett. President & CEO: Michael H. Madison. Inc.: Louisiana. Address: P.O. Box 5000, Pineville, Louisiana 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

Cleco's earnings are likely to decline in 2007. Some unusual items that benefited profits in 2006 will not occur this year. One of them is the $0.17 a share of income that Cleco booked from drawdowns of a letter of credit from Calpine after the latter company filed for bankruptcy protection (see below). A major planned outage at a generating unit in the fourth quarter will reduce earnings by $0.06 a share. And, average shares outstanding will rise due to a stock sale last year. A significant increase in the Allowance for Funds Used During Construction stemming from the building of Rodemacher Unit 3 will offset these factors to some extent. Cleco expects its earnings to wind up in a range of $1.20-$1.30 a share in 2007. We look for earnings to rise modestly in 2008 because Cleco won't have the aforementioned outage at the generating unit.

Construction of Rodemacher 3 is going well. Cleco expects to spend $1 billion to build the 600-megawatt facility, which will be powered by solid fuel (probably petroleum coke). It is due on line by late 2009. The unit will lessen the utility's dependence on natural gas and purchased power, the prices of which are costly and volatile. The company will probably issue some debt this year to help finance construction of Rodemacher 3, but the amount and timing of any issuances have not yet been determined.

Cleco is trying to resolve its problems regarding the Acadia project. Calpine had a contract to supply gas to Acadia and market its output, but rejected the contract after it filed for bankruptcy protection in late 2005. Acadia then became a merchant power plant, selling electricity into the market, and is unprofitable for Cleco. The company has stated that it hopes to make an announcement soon regarding Acadia.

Cleco's long-term prospects look brighter than its present ones. By the 2010-2012 period, with Rodemacher 3 (presumably) in the rate base, the company's earning power will be much higher. We expect dividend growth to resume over that time, too. At the current quotation, however, these untimely shares offer only average (by utility standards) 3- to 5-year total-return potential.

Paul E. Debbas, CFA *March 30, 2007*

(A) Primary EPS through '96, dil. thereafter. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢); '03, ($2.05); '05, $2.11; losses from disc. ops.: '00, 14¢; '01, 4¢. '04 & '05 EPS don't add due to rounding. Next earnings report due early May. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '05: $4.05/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '06: 11.65%; earned on avg. com. eq., '05: 12.7%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	50
Price Growth Persistence	60
Earnings Predictability	70

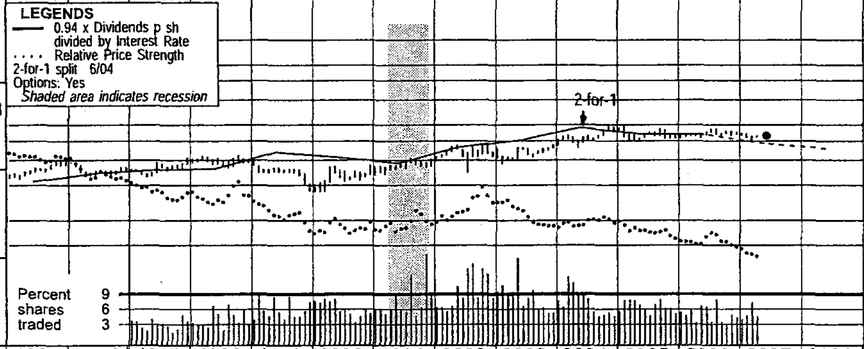
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE **26.58** | P/E RATIO **22.2** (Trailing: 20.0 Median: 13.0) | RELATIVE P/E RATIO **1.15** | DIV'D YLD **4.7%** | VALUE LINE

TIMELINESS **5** Lowered 12/1/06
SAFETY **2** Raised 2/15/02
TECHNICAL **4** Lowered 3/30/07
BETA .75 (1.00 = Market)

High:	19.8	20.8	21.3	20.3	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5
Low:	16.6	16.4	18.2	14.0	13.8	16.8	17.3	19.1	23.0	24.6	25.7	25.1

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-25%)	-2%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	2	0	0	2	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	3	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	74	87	84
to Sell	68	52	67
Hld's(000)	26259	26682	27384

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	2.6	12.1
3 yr.	21.7	53.0
5 yr.	43.2	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
22.71	20.83	20.64	20.74	21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	*29.95*	*30.40*	Revenues per sh	*34.00*
2.37	2.51	2.23	2.52	2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	*3.15*	*3.30*	"Cash Flow" per sh	*3.75*
1.20	1.27	1.19	1.30	1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	*1.30*	*1.40*	Earnings per sh A	*1.75*
1.11	1.13	1.15	1.17	1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	*1.24*	*1.24*	Div'd Decl'd per sh B ■ †	*1.24*
3.42	4.03	4.06	3.50	3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	*2.80*	*3.55*	Cap'l Spending per sh	*2.25*
12.18	11.06	11.62	11.90	12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	*13.60*	*13.95*	Book Value per sh C	*15.00*
47.73	49.52	55.35	57.31	59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	*83.50*	*85.50*	Common Shs Outst'g D	*87.00*
14.2	15.3	15.5	12.5	13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.91	.93	.92	.82	.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	*Value Line*		Relative P/E Ratio	*.95*
6.5%	5.8%	6.2%	7.2%	6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $1309.5 mill. Due in 5 Yrs $386.3 mill.
LT Debt $1123.2 mill. LT Interest $62.6 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.3x)
Pension Assets-12/06 $875.3 mill. **Oblig.** $985.6 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; *120,000 shs. 7⅝%, $100 par. call. $100.*
Sinking fund ends 2018.
Common Stock 81,471,220 shs.
as of 2/21/07
MARKET CAP: $2.2 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1464.0	1485.2	1523.3	1719.0	1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	*2500*	*2600*	Revenues ($mill)	*2950*
103.3	113.2	111.1	84.6	109.8	120.2	120.1	109.6	120.3	109.9	*110*	*125*	Net Profit ($mill)	*155*
34.9%	33.5%	33.9%	41.6%	34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	*40.0%*	*39.0%*	Income Tax Rate	*40.0%*
16.5%	14.2%	6.1%	9.8%	5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	*9.0%*	*12.0%*	AFUDC % to Net Profit	*6.0%*
43.4%	44.7%	47.2%	58.4%	56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*48.5%*
44.0%	43.1%	41.4%	39.9%	41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	*47.5%*	*47.5%*	Common Equity Ratio	*50.0%*
1851.3	1918.9	2049.5	2101.2	2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	*2395*	*2510*	Total Capital ($mill)	*2625*
2019.6	2093.4	2066.2	2091.3	2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	*2725*	*2865*	Net Plant ($mill)	*2975*
7.0%	7.4%	6.8%	5.9%	6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.5%*
9.8%	10.7%	10.3%	9.7%	11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	*9.5%*	*10.0%*	Return on Shr. Equity	*11.5%*
10.6%	11.4%	11.0%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	*9.5%*	*10.0%*	Return on Com Equity E	*12.0%*
3.0%	1.8%	1.5%	1.7%	4.4%	4.3%	3.9%	1.1%	1.5%	.7%	*.5%*	*1.5%*	Retained to Com Eq	*3.5%*
76%	87%	88%	84%	63%	63%	64%	87%	85%	93%	*94%*	*87%*	All Div'ds to Net Prof	*70%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+2.9	+.3	+.3
Avg. Indust. Use (MWH)	6816	6718	6623
Avg. Indust. Revs. per KWH (¢)	12.86	15.21	17.38
Capacity at Yearend (Mw)	2171	2184	2204
Peak Load, Winter (Mw)	1694	1641	1685
Annual Load Factor (%)	71.5	74.1	72.5
% Change Customers (yr-end)	+1.2	+1.7	+1.2
Fixed Charge Cov. (%)	335	325	301

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 434,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '06: residential, 34%; commercial, 34%; large light & power, 32%. Generating sources, '06: oil, 62%; purchased, 38%. Fuel costs: 52% of revs. '06 reported depr. rate (utility): 3.9%. Has 3,400 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.0%	2.0%	*4.0%*
"Cash Flow"	1.5%	-.5%	*3.0%*
Earnings	.5%	-1.0%	*4.0%*
Dividends	.5%	--	*Nil*
Book Value	1.5%	2.0%	*.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	437.1	461.8	506.8	518.4	1924.1
2005	472.6	522.3	595.9	624.8	2215.6
2006	574.9	605.0	673.9	607.1	2460.9
2007	*625*	*625*	*625*	*625*	*2500*
2008	*650*	*650*	*650*	*650*	*2600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.40	.14	.51	.31	1.36
2005	.30	.35	.46	.35	1.46
2006	.40	.33	.40	.20	1.33
2007	*.35*	*.30*	*.35*	*.30*	*1.30*
2008	*.38*	*.32*	*.38*	*.32*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.31	.31	.31	.31	1.24
2004	.31	.31	.31	.31	1.24
2005	.31	.31	.31	.31	1.24
2006	.31	.31	.31	.31	1.24
2007	.31				

One of Hawaiian Electric's utilities has received an interim order in its rate case. The Hawaii commission approved Hawaii Electric Light Company's (HELCO) settlement for a $24.6 million (7.6%) rate hike, based on a 10.7% return on 51.19% equity. Considering that HELCO received most of the $29.9 million it requested, we consider this a good outcome. The order calls for the utility to write off some plant costs, which will cause it to take a $7 million ($0.09-a-share) charge against first-quarter earnings. We will *exclude* this from our presentation as a nonrecurring item.

The company's other two utilities have rate cases pending. Hawaiian Electric Company (HECO) is seeking a $99.6 million (7.1%) tariff rate hike, based on an 11.25% return on a 55.1% common-equity ratio. HECO still hasn't received a final order in its previous case, in which it was granted an interim increase of $41.4 million (3.3%) based on a 10.7% ROE. Maui Electric Company (MECO) has requested a $19 million (5.3%) rate increase based on an 11.25% return on a 55.1% common-equity ratio. HECO and MECO should get interim decisions in late 2007 and early 2008, respectively. Separately, each utility will benefit from a regulatory order that allows the recovery of demand-side management program costs and provides for performance-based incentives.

The aforementioned regulatory activity was prompted largely by rising expenses. Higher costs have hurt the company's earnings in recent years, and this is likely to continue in 2007. Rate relief should help beginning in 2008, but we project that, even over the 3- to 5-year period, profits won't reach a level that would make a dividend increase probable. At least there appears to be no risk of a dividend cut for the time being.

Profits at American Savings Bank (ASB) are down. ASB is facing a lower interest-rate margin, higher credit costs, and higher noninterest expense. At least asset quality is still good.

This untimely stock's main attraction is its high yield. For the 3- to 5-year period, however, it is trading well within our 2010-2012 Target Price Range, and total-return potential over that time is poor.

Paul E. Debbas, CFA *May 11, 2007*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; 1Q '07, *(9¢)*. Next egs. due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '06: $2.45/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '05: HECO, 10.7% (interim); in '01: HELCO, 11.5%; in '99: MECO, 10.94%; earned on avg. com. eq., '06: 9.3%. Regulat. Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

MGE ENERGY INC. NDQ-MGEE

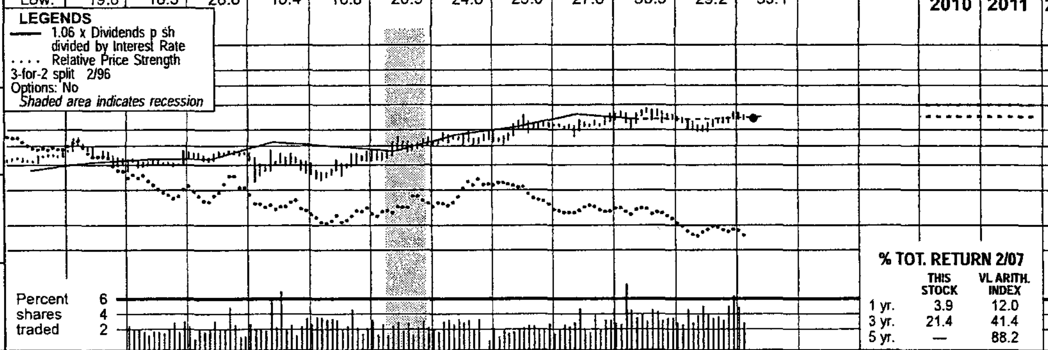
RECENT PRICE 34.32 | P/E RATIO 16.3 (Trailing: 16.7, Median: 16.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 8/25/06
SAFETY 1 New 1/3/03
TECHNICAL 4 Lowered 3/30/07
BETA .80 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	27.5	23.8	23.8	23.9	23.7	27.8	30.1	35.8	36.4	38.8	37.0	36.8
Low:	19.6	18.5	20.6	16.4	16.8	20.9	24.6	25.0	27.6	30.5	29.2	33.1

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.06 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 2/96
Options: No
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	8%
Low	35	(Nil)	5%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	36	37	44
to Sell	28	21	20
Hld's(000)	5521	5690	6060

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	3.9	12.0
3 yr.	21.4	41.4
5 yr.	—	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
14.47	14.21	15.18	15.23	15.46	15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	25.10	24.50	24.90	25.60	Revenues per sh	28.00
2.83	2.79	2.86	2.92	3.03	2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	3.00	3.05	3.30	3.40	"Cash Flow" per sh	4.10
1.52	1.45	1.51	1.53	1.49	.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.06	2.10	2.20	Earnings per sh A	2.55
1.17	1.19	1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.39	1.41	1.43	Div'd Decl'd per sh B ■	1.47
1.24	.77	1.47	1.64	1.19	1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	4.70	4.19	3.95	4.00	4.00	Cap'l Spending per sh	4.00
10.98	11.24	11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.81	16.95	17.95	18.70	Book Value per sh	19.45
16.05	16.05	16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.70	20.70	20.70	Common Shs Outst'g C	20.70
11.3	14.3	15.2	14.3	14.5	28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	17.1	Bold figures are		Avg Ann'l P/E Ratio	15.0
.72	.87	.90	.94	.97	1.76	.84	.84	.80	.76	.76	.87	1.00	.95	1.19	.92	Value Line		Relative P/E Ratio	1.00
6.8%	5.7%	5.2%	5.7%	5.8%	5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	estimates		Avg Ann'l Div'd Yield	4.6%

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
264.7	249.8	274.0	324.1	333.7	347.1	401.5	424.9	513.4	507.5	515	530	Revenues ($mill)	580
22.5	22.2	23.8	27.4	27.2	29.2	30.6	33.8	32.1	42.4	44.0	46.0	Net Profit ($mill)	43.0
37.5%	37.1%	36.9%	36.5%	36.9%	39.1%	39.4%	37.9%	38.2%	38.0%	38.0%	38.0%	Income Tax Rate	38.0%
.2%	.9%	1.9%	1.9%	2.2%	--	--	--	2.2%	1.7%	1.8%	1.8$	AFUDC % to Net Profit	2.0%
41.8%	46.7%	44.5%	47.8%	42.2%	45.8%	43.5%	37.4%	39.3%	39.5%	39.5%	39.0%	Long-Term Debt Ratio	39.0%
58.2%	53.3%	55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	60.5%	60.5%	61.0%	Common Equity Ratio	61.0%
310.8	342.0	334.3	383.7	373.9	419.5	465.3	540.5	566.2	590	615	635	Total Capital ($mill)	660
284.7	258.6	260.1	342.8	401.2	451.5	537.5	607.4	667.7	675	680	690	Net Plant ($mill)	700
8.8%	8.0%	8.0%	8.8%	9.0%	8.1%	7.8%	7.1%	6.6%	8.5%	8.5%	9.0%	Return on Total Cap'l	7.5%
12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	10.5%	12.0%	12.0%	Return on Shr. Equity	10.5%
12.4%	12.2%	12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	10.5%	12.0%	12.0%	Return on Com Equity D	10.5%
1.0%	.7%	1.5%	2.9%	2.3%	2.6%	2.5%	2.3%	1.2%	3.5%	4.0%	4.0%	Retained to Com Eq	3.0%
92%	94%	89%	79%	82%	79%	79%	77%	87%	68%	66%	64%	All Div'ds to Net Prof	71%

CAPITAL STRUCTURE as of 9/30/06
Total Debt $289.4 mill. **Due in 5 Yrs** $65.0 mill.
LT Debt $207.4 mill. **LT Interest** $12.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $1.4 mill.
Pension Assets-12/05 $116.7 mill.
Obligation $173.5 mill.

Pfd Stock None

Common Stock 20,670,572 shs.
as of 10/31/06
MARKET CAP: $700 million (Small Cap)

ELECTRIC OPERATING STATISTICS

	2003	2004	2005
% Change Retail Sales (KWH)	-1.6	+5.5	-0.7
Avg. Indust. Use (MWH)	4629	4624	4293
Avg. Indust. Revs. per KWH (¢)	4.11	4.40	4.37
Capacity at Peak (Mw)	768	763	812
Peak Load, Summer (Mw)	664	714	690
Annual Load Factor (%)	48.1	59.1	48.1
% Change Customers (avg.)	+.5	+1.0	+1.6
Fixed Charge Cov. (%)	352	388	352

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '10-'12
Revenues	4.0%	5.5%	.5%
"Cash Flow"	--	-5.0%	.5%
Earnings	1.0%	2.0%	6.0%
Dividends	1.0%	1.0%	.5%
Book Value	3.0%	6.5%	7.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	135.4	85.4	86.8	117.3	424.9
2005	138.9	100.5	114.4	159.6	513.4
2006	158.6	99.7	110.6	138.6	507.5
2007	160	103	114	138	515
2008	164	107	118	141	530

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.74	.30	.48	.25	1.77
2005	.40	.27	.48	.42	1.57
2006	.56	.34	.62	.54	2.06
2007	.58	.35	.63	.54	2.10
2008	.60	.38	.65	.57	2.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.336	.336	.338	.338	1.35
2004	.338	.338	.342	.342	1.36
2005	.342	.342	.345	.345	1.37
2006	.345	.345	.348	.348	1.39
2007	.348				

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to nearly 132,000 customers in a 250-square-mile area of Dane County and gas service to 129,000 customers in 1,375 square miles in seven counties in Wisconsin. Electric revenue breakdown, '05: residential, 33%; commercial, 48%; industrial, 6%; public authorities, 7%; other, 6%. Generating sources, '05: fossil-fueled steam, 62%; purchased power, 37%; other, 1%. Fuel costs: 43% of revenues. '05 reported depreciation rate: electric, 3.4%; gas, 3.3%. Has 750 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Telephone: 608-252-7000. Internet: www.mge.com.

MGE Energy posted sharply improved 2006 results. Share net at the electric utility and natural gas distributor increased 31%, year over year, to $2.06, on 1% lower revenue of $507.5 million. Mild weather across MGE's south-central and western Wisconsin service area limited the use of electricity/gas for residential heating and cooling. Still, share net benefited from sharply lower costs for electric fuel and purchased power. Hurricane-related damage to the nation's infrastructure had MGE paying more for fuel and purchased power in 2005. Thankfully, the 2006 hurricane season caused little, if any, supply disruptions or spikes in energy prices.

We look for more normalized earnings growth of 5% this year followed by low- to mid-single digit (per-annum) advances out to 2010-2012. Peak energy demand should increase 3% or so annually, net the effect of conservation initiatives. MGE should benefit from favorable demographics within its Dane County service area. Over the past few years, the population of Dane Country has been growing nearly 50% faster than the national average. Commercial and residential development in and around the city of Madison, in particular, should drive utility demand. Madison, including immediate suburbs, has a population of some 400,000 people and is home to the University of Wisconsin.

MGE may appeal to more environmentally conscious investors. The utility is aggressively developing renewable energy (R-E) sources and ought to easily meet state R-E mandates. MGE's 18-turbine addition to the Top of Iowa Wind Farm should triple its wind-generating capacity, to 45 megawatts. The utility also plans to eliminate coal burning at its Blount Generating Station and secure new cleaner-coal capacity.

MGE shares are ranked 3 (Average) for year ahead price performance. They've sold off since our December report and are now trading slightly below our our 3- to 5-year Target Price Range. The current quotation marks a decent entry point conservative, income-oriented investors. The current dividend yield, at 4.0%, is attractive, and regular, albeit modest, dividend increases are likely.

Nils C. Van Liew *March 30, 2007*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late April. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) In millions, adjusted for stock split. (D) Rate allowed on common equity in '02: 12.9%; earned on average common equity, '02: 13.0%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	60
Earnings Predictability	75

NORTHEAST UTILITIES NYSE-NU

RECENT PRICE 32.24 | P/E RATIO 23.0 (Trailing: 22.4 / Median: NMF) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 3 Raised 7/19/02
SAFETY 3 Raised 9/6/02
TECHNICAL 3 Lowered 5/25/07
BETA .90 (1.00 = Market)

High:	25.3	14.3	17.3	22.0	24.6	24.3	20.7	20.3	20.3	22.0	28.9	33.6			Target Price Range
Low:	9.5	7.6	11.7	13.6	18.0	16.6	12.7	13.1	17.2	17.3	19.1	27.2			2010 | 2011 | 2012

2010-12 PROJECTIONS

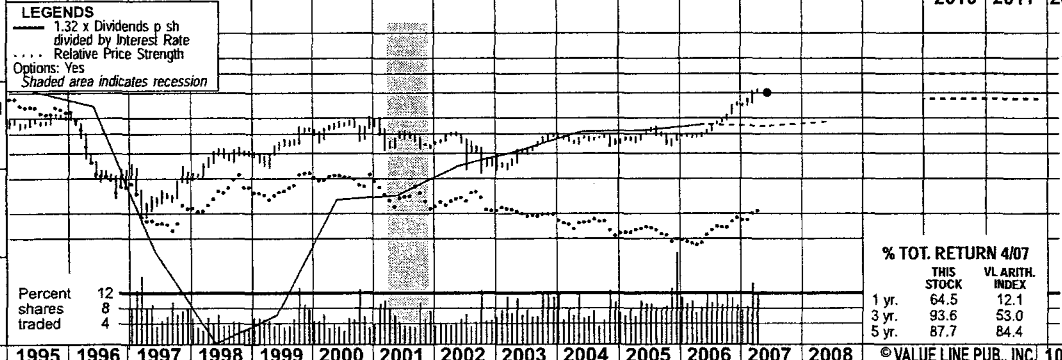
	Price	Gain	Ann'l Total Return
High	40	(+25%)	8%
Low	30	(-5%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	1	0	0	5
to Sell	0	0	0	0	1	1	0	0	5

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	98	87	130
to Sell	88	85	79
Hld's(000)	119815	114648	113929



% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	64.5	12.1
3 yr.	93.6	53.0
5 yr.	87.7	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
23.09	24.03	29.19	29.15	29.51	29.52	29.46	28.77	33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	*37.50*	*38.95*	Revenues per sh	*43.00*
4.66	5.13	5.86	6.26	6.02	3.77	2.68	3.73	5.68	3.39	10.48	6.32	5.80	5.00	5.46	2.34	*3.20*	*3.65*	"Cash Flow" per sh	*4.55*
2.12	2.02	1.60	2.30	2.24	.01	d1.05	d.36	d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	*1.40*	*1.55*	Earnings per sh (A)	*1.80*
1.76	1.76	1.76	1.76	1.76	1.38	.25	--	.10	.40	.45	.53	.58	.63	.68	.73	*.78*	*.83*	Div'd Decl'd per sh (B)■	*.98*
2.10	2.37	2.49	2.31	1.97	1.85	1.85	1.79	2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	*7.70*	*5.70*	Cap'l Spending per sh	*4.25*
15.73	16.24	17.89	18.48	19.08	17.73	16.34	15.63	15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	*18.90*	*19.75*	Book Value per sh (C)	*22.60*
119.25	133.86	124.33	124.96	127.05	128.44	130.18	130.95	131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	*156.20*	*158.20*	Common Shs Outst'g (D)	*164.20*
10.1	12.3	16.6	10.0	10.3	NMF	--	--	--	--	14.1	16.1	13.4	20.8	19.8	27.1	Bold figures are		Avg Ann'l P/E Ratio	*19.5*
.65	.75	.98	.66	.69	NMF	--	--	--	--	.72	.88	.76	1.10	1.05	1.46	Value Line		Relative P/E Ratio	*1.30*
8.3%	7.1%	6.6%	7.7%	7.6%	8.9%	2.4%	--	.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	estimates		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 3/31/07
Total Debt $3772 mill. Due in 5 Yrs $2624 mill.
LT Debt $3264 mill. LT Interest $164.1 mill.

(LT interest earned: 1.4x)

Pension Assets-12/06 $2.4 bill. Oblig. $2.3 bill.
Pfd Stock $116.2 mill. Pfd Div'd $5.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.

Common Stock 154,553,804 shs. as of 4/30/07

MARKET CAP: $5.0 billion (Large Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
3834.8	3767.7	4471.3	5876.6	6873.8	5216.3	6069.2	6686.7	5507.3	6884.4	*5860*	*6160*	Revenues ($mill)	*7060*
d96.1	d11.8	d127.0	d14.4	186.4	144.2	162.7	122.1	128.5	126.2	*220*	*250*	Net Profit ($mill)	*300*
--	NMF	--	--	--	--	32.1%	29.8%	30.8%	30.8%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
--	--	--	--	--	9.2%	7.1%	6.8%	6.8%	21.5%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*5.0%*
58.5%	57.9%	49.9%	45.7%	65.9%	64.3%	63.9%	64.2%	63.2%	58.7%	*50.5%*	*51.0%*	Long-Term Debt Ratio	*49.0%*
33.8%	35.2%	42.7%	48.8%	32.4%	33.9%	34.3%	34.0%	35.1%	39.7%	*47.5%*	*47.5%*	Common Equity Ratio	*49.5%*
6285.3	5821.7	4876.0	4546.6	6544.7	6513.2	6591.6	6749.4	6923.2	7052.0	*6230*	*6605*	Total Capital ($mill)	*7485*
6463.2	6170.9	3947.4	3547.2	3822.1	4728.4	5429.9	5864.2	6417.2	6242.2	*7170*	*7740*	Net Plant ($mill)	*8810*
.7%	2.1%	.0%	1.9%	4.6%	4.1%	4.2%	2.8%	3.5%	2.9%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.0%*
NMF	NMF	NMF	NMF	8.3%	6.2%	6.8%	5.1%	5.0%	4.3%	*7.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
NMF	NMF	NMF	NMF	8.5%	6.3%	6.9%	5.1%	5.1%	4.3%	*7.0%*	*8.0%*	Return on Com Equity (E)	*8.0%*
NMF	NMF	NMF	NMF	5.6%	3.2%	3.7%	1.6%	1.5%	.3%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
NMF	NMF	NMF	NMF	37%	51%	48%	70%	72%	94%	*58%*	*55%*	All Div'ds to Net Prof	*55%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.6	+9.7	-4.1
Avg. Indust. Use (MWH)	814	809	776
Avg. Indust. Revs. per KWH (¢)	8.26	8.19	7.76
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+2.0	+.2
Fixed Charge Cov. (%)	168	156	79

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.5%	1.5%	2.5%
"Cash Flow"	-2.0%	-8.0%	1.0%
Earnings	-5.0%	--	12.0%
Dividends	-8.5%	16.5%	6.5%
Book Value	--	3.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1838	1524	1668	1657	6687
2005	1407	1238	1424	1438	5507
2006	2147	1661	1593	1483	6884
2007	1704	*1350*	*1400*	*1406*	*5860*
2008	*1780*	*1425*	*1475*	*1480*	*6160*

Cal-endar	EARNINGS PER SHARE (A) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.53	.18	d.06	.26	.91
2005	.45	.14	.06	.33	.98
2006	d.13	.09	.67	.19	.82
2007	.49	*.15*	*.45*	*.31*	*1.40*
2008	*.53*	*.17*	*.50*	*.35*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID (B)■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.138	.138	.15	.15	.58
2004	.15	.15	.163	.163	.63
2005	.163	.163	.175	.175	.68
2006	.175	.175	.188	.188	.73
2007	.188	.188	.20		

BUSINESS: Northeast Utilities is the parent of the NU sys, which is the largest utility in New England and serves two million electricity and gas customers. Connecticut Light & Power provides service to most of Conn; Public Service Co. of New Hampshire supplies power to three quarters of New Hampshire's population; Western Massachusetts Electric Co. serves the western half of Mass. Acq'd Yankee Energy 3/00. 2006 revs: resid'l, 48%; comm'l, 39%; ind'l, 12%; other 1%. Gen. sources: fossil (steam), hydro, and purchased power. Fuel & Purch. Pwr. costs: 67% of '06 revs. '06 deprec. rate: 3.2%. Has 5,867 employees. Chrmn, Pres. & CEO: Charles W. Shivery. Inc.: CT. Addr.: P.O. Box 270, Hartford, CT 06141. Tel.: 800-999-7269. Web: www.nu.com.

Northeast Utilities has three transmission projects under way. The largest is a 69-mile line from Norwalk to Middletown, in which NU has an 80% stake. To satisfy landowners whose property lies en route, 20 miles will be built underground. That raised the estimated cost several hundred million dollars, to $1.3 billion. On completion in 2009, the facility will increase energy imports into southwest Connecticut by some 1,300 megawatts. NU is also constructing a nine-mile underground line between Norwalk and Stamford, for $183 million, to strengthen connections in that area. Too, NU has a 50% stake in an 11-mile undersea cable between Connecticut and Long Island that is 35 years old and will be replaced to improve reliability. The unit is due on line next year at a cost of $144 million. Management projects that these additions and infrastructure upgrades will cost $4 billion through 2010. Debt and equity offerings will be needed to cover the outlays.

One rate order is in place. Two remain outstanding. Last March, NU received $37.7 million in New Hampshire in addition to a temporary hike of $24.5 million the previous July. In Connecticut, it awaits a regulatory decision on a $19.4 million settlement agreement with interested parties to cover the cost of the Yankee Gas liquified natural gas storage facility, which will be operative in the coming heating season. Finally, NU will soon file for higher electric and gas distribution rates at its Connecticut L&P utility. An order here is expected in December.

Earnings should have no difficulty surpassing last year's weak results. (Note: Our 2006 presentation excludes gains of $2.23 a share from the sale of high-risk, generation assets, because of their nonrecurring nature.) Based on a full year of rate relief in New Hampshire and recovery of transmission expenditures on a regular basis, we estimate 2007 earnings will rise 70%, to $1.40 a share. A much smaller increase is likely next year.

The stock is an average utility investment. Though the year-ahead yield is below the industry norm, dividend growth potential to 2010-2012 exceeds that of the group. At the share's recent price, total return prospects are only average.

Arthur H. Medalie — *June 1, 2007*

(A) Basic egs. EPS may not add due to change in share count. Excl. nonrecur. items: '99, $1.40; '01, 42¢; '02, 10¢; '03, d32¢; '04, d7¢; 1Q, '05, d$1.36; '06, $2.23. Incl. ind. restruct. chgs: '00, $1.51. Next egs rpt early Aug. (B) Div'd suspended 2Q, '97; reinstated 4Q, '99. Div'ds hist. paid late Mar., June, Sep., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. def'd chgs '06: $21.59/sh. (D) In mill. (E) Rate allowed on com. eq.: MA., '99: 11%; CT, '03: 9.85%; NH, '97: 11%. Earned on avg. com. eq.: '06, 4.8%. Regulatory Climate: Below avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	50
Earnings Predictability	25

NSTAR NYSE-NST

RECENT PRICE	36.33	P/E RATIO	17.7 (Trailing: 18.3) (Median: 14.0)	RELATIVE P/E RATIO	0.92	DIV'D YLD	3.7%	VALUE LINE

TIMELINESS	4	Lowered 12/8/06
SAFETY	1	Raised 6/11/99
TECHNICAL	4	Lowered 5/25/07

BETA .80 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(-5%)	4%

Insider Decisions

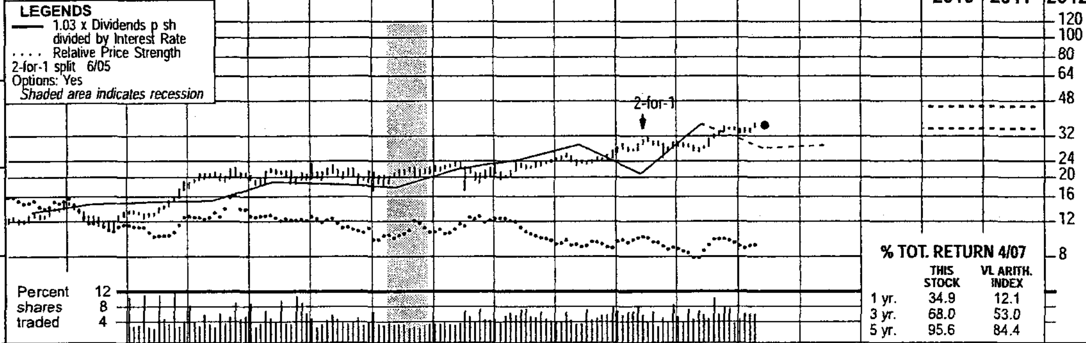
	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	2	2	0	6	0	0	0	0	0
to Sell	2	2	0	6	1	0	0	2	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	96	115	123
to Sell	94	84	85
Hld's(000)	45568	47591	48400

High:	15.1	19.2	22.5	22.3	23.5	22.6	24.1	24.5	27.2	31.5	35.9	37.4		
Low:	10.9	12.3	17.5	18.2	18.2	17.0	17.0	19.3	22.7	24.9	26.5	32.7		

Target Price Range 2010 | 2011 | 2012



% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	34.9	12.1
3 yr.	68.0	53.0
5 yr.	95.6	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
15.69	15.77	16.42	17.00	16.96	17.17	18.31	17.19	15.94	25.45	30.09	25.64	27.48	27.73	30.36	33.50	*33.70*	*35.80*	Revenues per sh	*43.00*
2.87	2.94	2.98	3.35	3.11	3.65	3.66	3.84	3.04	3.78	3.81	3.95	3.98	4.09	5.00	5.40	*5.60*	*5.90*	"Cash Flow" per sh	*6.75*
.98	1.05	1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.93	*2.05*	*2.25*	Earnings per sh A	*3.00*
.80	.83	.86	.89	.92	.94	.94	.95	.98	1.01	1.04	1.07	1.09	1.13	.87	1.54	*1.33*	*1.43*	Div'd Decl'd per sh B ■	*1.75*
2.55	2.58	2.81	2.42	2.08	2.13	1.23	1.57	1.53	1.78	2.22	3.50	2.94	2.95	3.63	3.99	*3.80*	*2.95*	Cap'l Spending per sh	*2.75*
8.96	9.39	9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.37	14.82	*15.55*	*16.40*	Book Value per sh C	*19.75*
84.09	89.53	90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	*106.81*	*106.81*	Common Shs Outst'g D	*106.81*
10.6	11.9	13.1	10.7	12.3	9.7	10.6	14.6	14.6	12.9	12.7	12.7	12.8	14.0	15.5	15.9	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.5*
.68	.72	.77	.70	.82	.61	.61	.76	.83	.84	.65	.69	.73	.74	.83	.86	*estimates*		Relative P/E Ratio	*.90*
7.7%	6.6%	5.8%	6.9%	7.2%	7.4%	6.5%	4.7%	4.8%	4.9%	5.0%	4.9%	4.9%	4.6%	3.1%	5.0%			Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 3/31/07
Total Debt $2979.2 mill. **Due in 5 Yrs** $1814.9 mill.
LT Debt $2324.3 mill. **LT Interest** $144.1 mill.
Incl. $558.6 mill. securitized bonds.
(LT interest earned: 3.0x)
Leases, Uncapitalized *Annual rentals $18.1 mill.*
Pension Assets-12/06 $1.03 bill. **Oblig.** $1.08 bill.
Pfd Stock $43.0 mill. **Pfd Div'd** $2.0 mill.
430,000 shs. 4.25%-4.78%, cum., redeemable at $102.80-$103.625.
Common Stock 106,808,376 shs.
as of 4/27/07
MARKET CAP: $3.9 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1776.2	1622.5	1851.4	2699.5	3191.8	2719.1	2914.1	2954.3	3243.1	3577.7	*3600*	*3825*	Revenues ($mill)	*4600*
144.6	141.0	146.5	181.0	179.1	181.3	188.0	190.4	198.1	208.7	*225*	*245*	Net Profit ($mill)	*315*
36.3%	34.3%	29.1%	41.6%	41.4%	35.8%	37.5%	38.5%	35.6%	37.8%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
.8%	1.2%	1.5%	2.5%	2.8%	1.6%	2.4%	.5%	1.9%	3.3%	*3.0%*	*2.0%*	AFUDC % to Net Profit	*1.0%*
46.1%	45.5%	50.0%	59.4%	59.2%	60.9%	58.5%	58.6%	60.4%	59.2%	*56.0%*	*55.0%*	Long-Term Debt Ratio	*43.5%*
46.5%	50.1%	47.2%	39.4%	39.5%	37.8%	40.2%	40.2%	38.6%	39.7%	*42.5%*	*44.0%*	Common Equity Ratio	*55.5%*
2291.6	2099.5	3269.3	3409.8	3197.4	3433.7	3387.1	3585.3	3980.4	3986.3	*3895*	*3975*	Total Capital ($mill)	*3800*
2854.1	2270.7	2550.6	2523.6	2625.4	2847.6	3216.1	3425.0	3701.8	3945.3	*4135*	*4225*	Net Plant ($mill)	*4400*
8.3%	8.7%	6.1%	7.6%	8.1%	7.5%	7.8%	7.4%	7.1%	7.3%	*7.5%*	*8.0%*	Return on Total Cap'l	*9.5%*
11.7%	12.3%	9.0%	13.1%	13.7%	13.5%	13.4%	12.8%	12.6%	12.8%	*13.0%*	*13.5%*	Return on Shr. Equity	*14.5%*
12.3%	12.6%	9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	13.1%	*13.5%*	*13.5%*	Return on Com Equity E	*15.0%*
3.7%	3.9%	2.4%	4.8%	5.0%	5.2%	5.1%	4.8%	4.6%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
73%	71%	74%	64%	65%	63%	63%	64%	64%	63%	*64%*	*64%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.5	+2.5	-1.9
Avg. Indust. Use (MWH)	1027	1022	1001
Avg. Indust. Revs. per KWH (¢)	7.90	8.20	8.40
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	4254	4682	4958
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (avg.)	+.4	+.7	+1.5
Fixed Charge Cov. (%)	287	266	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	6.0%	5.0%	*6.0%*
"Cash Flow"	3.5%	6.5%	*5.5%*
Earnings	4.5%	3.5%	*8.5%*
Dividends	2.5%	3.0%	*7.0%*
Book Value	3.5%	2.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	809.9	649.8	781.5	713.1	2954.3
2005	880.0	692.0	858.5	812.6	3243.1
2006	1034.8	784.6	956.3	802.0	3577.7
2007	984.4	*800*	*1000*	*815.6*	*3600*
2008	*1075*	*850*	*1050*	*850*	*3825*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.46	.35	.59	.35	1.76
2005	.43	.31	.72	.36	1.83
2006	.41	.43	.72	.38	1.93
2007	.45	*.44*	*.73*	*.43*	*2.05*
2008	*.50*	*.48*	*.80*	*.47*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.27	.27	.27	.27	1.08
2004	.278	.278	.278	.278	1.11
2005	.29	.29	.29	.29	1.16
2006	.303	.303	.303	.303	1.21
2007	.325	.325			

BUSINESS: NSTAR is a holding company for Boston Edison Company, which supplies electricity to an area of approx. 590 sq. mi. in eastern Massachusetts, encompassing Boston and 39 surrounding towns and cities, and Commonwealth Energy (acq'd 8/99), which provides electric and gas service in eastern Massachusetts. Serves 1.1 million electric, 300,000 gas customers. Electric revenue breakdown, '06: residential, 43%; commercial, 52%; industrial, 5%; other, less than 1%. Sold fossil plants in '98, nuclear plant in '99. Fuel costs: 59% of revenues. '06 reported deprec. rate: 3.0%. Has 3,100 employees. Chairman, President & CEO: Thomas J. May. Inc.: Massachusetts. Address: 800 Boylston St., Boston, Massachusetts 02199-8003. Tel.: 617-424-2000. Internet: www.nstaronline.com.

We have trimmed our 2007 earnings estimate for NSTAR by a nickel a share, to $2.05. That's because first-quarter earnings of $0.45 a share, although up from $0.41 a share a year earlier (thanks in part to a return to normal weather patterns), were below our estimate of $0.49 a share. Profits should still wind up well above the 2006 tally, however. NSTAR is benefiting from a regulatory agreement in Massachusetts that took effect last May, and the utility is earning a healthy return (regulated by the Federal Energy Regulatory Commission) on a $220 million transmission project it has been building during the past couple of years. Our revised estimate for 2007 is still within the company's targeted range of $2.02-$2.12 a share. NSTAR shares are ranked 4 (Below Average) for year-ahead relative performance.

We estimate that earnings will climb 10% in 2008. The aforementioned regulatory agreement in Massachusetts runs through 2012 and provides annual incremental benefits for the company. Also, the costs of programs to improve customer service and accelerate staffing to address the effects of an aging workforce should be limited to 2007.

There will probably be four common dividend declarations in 2007. Ordinarily, this wouldn't be worth mentioning. But the dividend declaration that was originally scheduled for the fourth quarter of 2005 was postponed until the first quarter of 2006. Accordingly, there were just three declarations in 2005 and five last year. That's why there are unusual fluctuations in the "dividends declared" line in the statistical array above, despite the fact that NSTAR has established a record of dividend growth dating back to the late 1990s. Even with the change in the declaration dates, common stockholders still received their dividend payments on schedule.

This stock is suitable for conservative, income-oriented investors. It is ranked 1 (Highest) for Safety. Its yield is a bit above the utility average. In addition, NSTAR offers better 3- to 5-year earnings and dividend growth potential than most utilities, so total-return potential through 2010-2012 is above the industry average as well.

Paul E. Debbas, CFA *June 1, 2007*

(A) Diluted EPS. Excl. nonrecurring losses: '01, $1.66 net; '02, 17¢; '03, 4¢. '04,'05, & '06 EPS don't add to full-year total due to rounding. Next earnings report due late July. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. There were only 3 div'd declarations in '05, 5 in '06. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '06: $2.5 bill., $23.52/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '06: 12.5%; earned on avg. com. eq., '06: 13.3%. Regulatory Climate: Above Average.

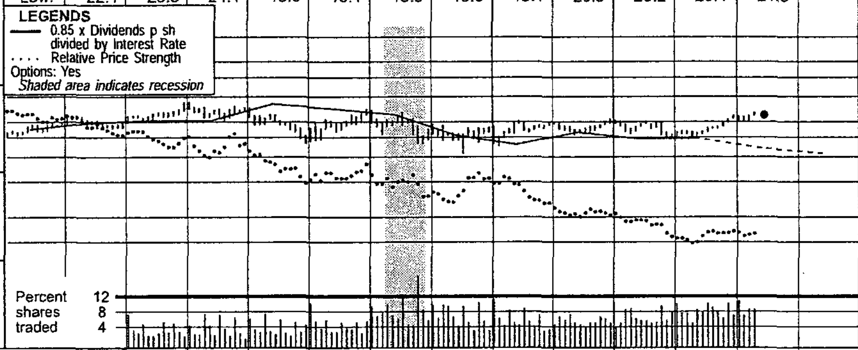
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

PUGET ENERGY, INC. NYSE-PSD

RECENT PRICE	26.06	P/E RATIO	17.1 (Trailing: 18.1 Median: 16.0)	RELATIVE P/E RATIO	0.89	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS 3 Lowered 2/16/07
SAFETY 3 Lowered 10/19/01
TECHNICAL 3 Raised 4/6/07
BETA .85 (1.00 = Market)

High:	26.0	30.2	30.3	28.4	28.0	27.8	23.6	24.4	24.8	24.6	25.9	26.9
Low:	22.1	23.5	24.1	18.6	19.1	18.5	16.6	18.1	20.5	20.2	20.1	24.0



Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+15%)	7%
Low	20	(-25%)	-1%

Insider Decisions

	J	J	A	S	O	N	D	J	F
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	1	5
to Sell	0	0	0	0	0	2	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	97	106	114
to Sell	89	64	75
Hld's(000)	72569	72824	71969

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.6	12.1
3 yr.	34.2	53.0
5 yr.	55.8	84.4

Puget Sound Energy (PSE) was formed through the merger of Puget Sound Power & Light and Washington Energy effective February 11, 1997. Shareholders of Washington Energy received .86 of a share of Puget Sound P&L stock for each Washington Energy share. PSE changed its name to Puget Energy when it formed a holding company at the start of 2001.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
19.83	22.56	24.34	40.06	38.77	25.55	25.15	25.72	22.24	24.93	26.05	27.20	Revenues per sh	30.25
3.19	3.81	3.98	4.52	3.78	3.80	3.90	4.02	3.56	3.96	4.35	4.55	"Cash Flow" per sh	5.25
1.28	1.85	1.91	2.16	1.22	1.24	1.22	1.32	1.42	1.44	1.60	1.65	Earnings per sh A	2.00
1.84	1.84	1.84	1.84	1.84	1.21	1.00	1.00	1.00	1.00	1.00	1.00	Div'd Decl'd per sh B ■ †	1.20
3.11	4.05	3.96	3.56	3.11	2.67	3.09	3.55	5.28	6.74	4.55	5.30	Cap'l Spending per sh	5.25
16.06	16.00	16.24	16.61	15.66	16.27	16.71	16.24	17.52	18.15	18.80	19.45	Book Value per sh C	22.00
84.56	84.56	84.92	85.90	87.02	93.64	99.07	99.87	115.70	116.58	117.00	117.75	Common Shs Outst'g D	124.25
20.4	14.6	12.3	10.8	19.1	17.1	18.1	17.1	15.8	15.4	Bold figures are		Avg Ann'l P/E Ratio	13.0
1.18	.76	.70	.70	.98	.93	1.03	.90	.84	.83	Value Line		Relative P/E Ratio	.85
7.1%	6.8%	7.8%	7.9%	7.9%	5.7%	4.5%	4.4%	4.5%	4.5%	estimates		Avg Ann'l Div'd Yield	4.6%
1676.9	1907.3	2066.6	3441.7	3374.0	2392.3	2491.5	2568.8	2573.2	2905.7	3050	3200	Revenues ($mill)	3750
125.7	169.6	173.3	193.8	113.6	117.9	122.6	131.7	146.4	167.3	185	195	Net Profit ($mill)	255
33.2%	40.0%	37.8%	39.5%	40.6%	32.7%	36.4%	37.7%	37.0%	35.6%	30.0%	30.0%	Income Tax Rate	30.0%
4.1%	4.5%	6.1%	6.2%	6.3%	3.9%	4.0%	5.2%	8.4%	11.1%	5.0%	8.0%	AFUDC % to Net Profit	6.0%
46.4%	47.6%	52.6%	59.5%	62.2%	60.1%	57.6%	60.5%	54.4%	55.5%	57.0%	56.5%	Long-Term Debt Ratio	51.5%
44.6%	43.7%	40.7%	37.4%	34.9%	37.4%	42.4%	39.4%	45.6%	44.4%	43.0%	43.5%	Common Equity Ratio	48.5%
3043.4	3095.7	3387.9	3815.6	3900.4	4076.7	3906.7	4116.9	4450.0	4764.0	5120	5250	Total Capital ($mill)	5625
3250.5	3430.9	3750.9	3838.4	3888.0	3916.2	4080.2	4228.4	4630.9	5181.0	5510	5795	Net Plant ($mill)	6750
5.6%	7.1%	7.1%	7.0%	5.2%	4.9%	5.2%	5.3%	5.2%	5.3%	5.5%	5.5%	Return on Total Cap'l	6.0%
7.7%	10.5%	10.8%	12.5%	7.7%	7.2%	7.4%	8.1%	7.2%	7.9%	8.5%	8.5%	Return on Shr. Equity	9.5%
7.9%	11.6%	11.8%	13.0%	7.7%	7.2%	7.0%	8.1%	7.2%	7.9%	8.5%	8.5%	Return on Com Equity E	9.5%
NMF	.1%	1.0%	3.6%	NMF	1.3%	2.1%	2.8%	2.9%	3.0%	3.0%	3.5%	Retained to Com Eq	4.0%
NMF	99%	92%	74%	125%	83%	72%	66%	60%	62%	63%	61%	All Div'ds to Net Prof	59%

CAPITAL STRUCTURE as of 12/31/06
Total Debt $3099.2 mill. **Due in 5 Yrs** $1282.6 mill.
LT Debt $2646.1 mill. **LT Interest** $177.3 mill.
Incl. $37.8 mill. tax-deductible preferred securities with interest rate of 8.231%.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $13.8 mill.
Pension Assets-12/06 *$532.6 mill.* ***Oblig.*** *$469.0 mill.*
Pfd Stock $1.9 mill. **Pfd Div'd** $.1 mill.
4,311 shs. 4.70%, 14,583 shs. 4.84%, $100 par, callable $101 to $102. All shares cumulative.
Common Stock 116,723,205 shs.
as of 2/21/07
MARKET CAP: $3.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+1.5	+3.0	+3.1
Avg. Indust. Use (MWH)	340	350	370
Avg. Indust. Revs. per KWH (¢)	6.56	6.92	7.53
Capacity at Yearend (Mw)	4351	4360	4456
Peak Load, Winter (Mw)	4351	4360	4456
Annual Load Factor (%)	53.5	57.4	53.5
% Change Customers (yr-end)	+2.4	+1.6	+2.1
Fixed Charge Cov. (%)	214	224	230

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	2.5%	-6.5%	3.5%
"Cash Flow"	1.0%	-1.0%	5.5%
Earnings	-2.5%	-4.5%	6.0%
Dividends	-6.0%	-11.5%	3.0%
Book Value	-.5%	1.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	743.5	515.9	515.0	794.4	2568.8
2005	741.6	510.1	490.4	831.1	2573.2
2006	877.7	574.2	519.5	934.3	2905.7
2007	1003.9	600	575	871.1	3050
2008	1050	625	600	925	3200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.67	d.07	.11	.61	1.32
2005	.72	.12	.06	.52	1.42
2006	.63	.18	.14	.49	1.44
2007	.68	.20	.15	.57	1.60
2008	.70	.20	.15	.60	1.65

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.25	.25	.25	.25	1.00
2004	.25	.25	.25	.25	1.00
2005	.25	.25	.25	.25	1.00
2006	.25	.25	.25	.25	1.00
2007	.25				

BUSINESS: Puget Energy, Inc. is a holding company for Puget Sound Energy (PSE), which sells electricity and gas to 1.4 million customers in a 6,000-sq.-mi. region in western Washington. Merged with Washington Energy 2/97. Discontinued InfrastruX (utility construction services) in '05. Electric revenue breakdown, '06: residential, 45%; commercial, 40%; industrial, 6%; other, 9%. Generating sources, '06: coal, 20%; hydro, 4%; oil & gas, 3%; wind, 1%; purchased, 72%. Fuel costs: 60% of revenues. '06 reported deprec. rates: 2.9% electric, 3.3% gas. Has 2,400 employees. Chairman: Douglas P. Beighle. President & CEO: Stephen P. Reynolds. Inc.: Washington. Address: P.O. Box 97034, Bellevue, Washington 98009-9734. Tel.: 425-454-6363. Internet: www.pugetenergy.com.

Puget Energy's utility subsidiary has filed a power-cost-only rate case to recover the cost of a power plant it acquired. Puget Sound Energy paid $120 million for the 277-megawatt Goldendale gas-fired plant. The advantage of a power-cost-only case, versus a full-blown rate case, is a streamlined regulatory process with an order in five months, not 11. The utility is seeking a $65 million (3.7%) rate hike to recover the cost of Goldendale. The decision of the Washington commission is due in time for new rates to take effect at the start of September.

Meeting the utility's power needs is a key challenge. Historically, PSE has purchased most of its power, but this option is less attractive since purchased-power costs became increasingly volatile several years ago. But options for adding generating capacity in Washington are limited. Coal-fired plants raise too many environmental concerns, and PSE, without any ownership in nuclear power, isn't about to consider such a facility. So, gas and wind are it. Goldendale is the second gas-fired plant that PSE has purchased in recent years, and the utility built 580 megawatts of wind capacity in 2005 and 2006. Gas is costly, and wind plants run less than half the time, so there is no "ideal" option for the company.

We expect a significant earnings increase in 2007, followed by a more modest rise in 2008. This year, the fourth-quarter comparison should be relatively easy, since PSE swallowed $10.9 million of storm-related expenses in the fourth period of 2006. (The utility deferred $92.3 million of these costs for future recovery.) We have trimmed our 2007 estimate by a nickel a share, but it is still within the company's targeted range of $1.50-$1.65. We figure that growth in demand will produce an earnings uptick in 2008. We aren't estimating a dividend increase next year, but we don't rule one out, either.

This stock offers a decent dividend yield. But, even with our projection of earnings and dividend growth 3 to 5 years out, with the issue trading well within our 2010-2012 Target Price Range, total-return potential over that time is unimpressive.

Paul E. Debbas, CFA *May 11, 2007*

(A) Diluted EPS. Excl. nonrec. gain (losses): '99, 15¢; '01, (8¢) net; '04, (77¢); gains (loss) on discont. ops.: '97, (3¢); '05, 9¢; '06, 45¢. Incl. merger costs: '97, 43¢. Next earnings report due late July. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '06: $283.2 mill., $2.43/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '07: 10.4%; earned on avg. com. eq., '06: 8.7%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	15
Earnings Predictability	50

UIL HOLDINGS NYSE-UIL

RECENT PRICE 33.50 | P/E RATIO 18.1 (Trailing: 17.4 Median: 15.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS 4 Lowered 3/2/07

SAFETY 3 Lowered 12/6/02

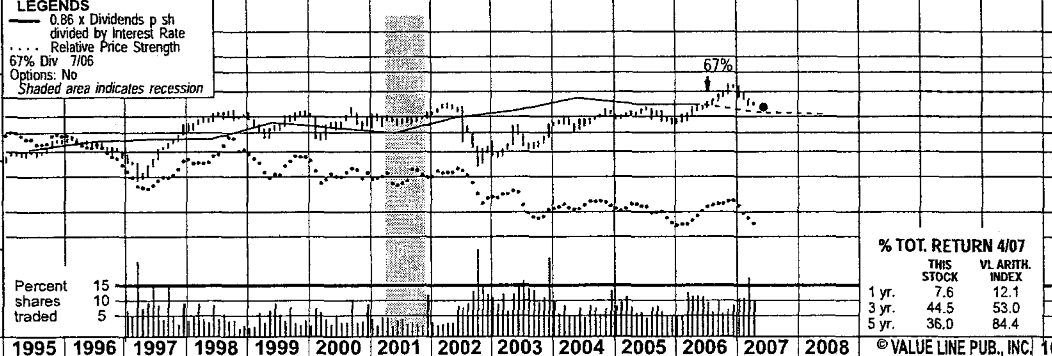
TECHNICAL 4 Lowered 5/11/07

BETA .95 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	24.0	27.6	32.5	32.2	33.6	31.8	35.3	27.6	32.8	33.7	43.8	43.0
Low:	18.7	14.2	25.0	23.3	22.7	26.3	16.9	18.5	25.1	27.4	27.4	33.2

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 0.86 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
67% Div 7/06
Options: No
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	30	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	2	0	0	3	0	0	0	0
to Sell	1	2	0	0	3	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	62	57	82
to Sell	40	54	34
Hld's(000)	11519	11770	12105

Percent shares traded 15 10 5

% TOT. RETURN 4/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.6	12.1
3 yr.	44.5	53.0
5 yr.	36.0	84.4

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
29.00	28.53	27.82	27.97	29.38	30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	*41.25*	*44.90*	Revenues per sh	*51.90*
4.79	4.90	4.90	4.77	4.91	4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	*5.00*	*5.85*	"Cash Flow" per sh	*7.40*
1.93	1.90	1.88	1.91	2.18	1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	*1.85*	*1.95*	Earnings per sh A	*2.15*
1.46	1.54	1.60	1.66	1.69	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
2.72	2.84	4.04	2.69	2.53	2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	*10.35*	*5.50*	Cap'l Spending per sh	*3.75*
17.30	18.07	18.03	18.23	18.72	18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	*18.70*	*19.05*	Book Value per sh C	*19.95*
23.22	23.39	23.47	23.48	23.50	23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	*25.20*	*25.40*	Common Shs Outst'g E	*26.60*
10.6	11.9	13.6	10.5	9.3	11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	*16.5*
.68	.72	.80	.69	.62	.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	estimates		Relative P/E Ratio	*1.10*
7.2%	6.8%	6.2%	8.2%	8.3%	8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%			Avg Ann'l Div'd Yield	*4.9%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $486.9 mill. Due in 5 Yrs. $291.4 mill.
LT Debt $408.6 mill. LT Interest $21.5 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized: Ann. rentals $13.4 mill.

Pension Assets-12/06 $317 mill. Oblig. $362 mill.

Pfd Stock None

Common Stock 24,856,043 shs.

MARKET CAP: $825 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
710.3	686.2	680.0	880.9	1085.8	1131.0	963.7	1101.3	1213.1	846.0	*1040*	*1140*	Revenues ($mill)	*1380*
45.8	42.2	52.2	59.9	59.4	44.0	29.5	36.9	31.4	45.4	*46.0*	*49.0*	Net Profit ($mill)	*57.0*
47.4%	56.0%	56.0%	44.5%	44.8%	45.2%	53.1%	45.4%	44.1%	31.2%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
3.5%	1.1%	4.3%	4.4%	3.2%	5.1%	8.5%	1.1%	9.0%	8.0%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*3.0%*
57.3%	57.7%	50.5%	52.2%	49.9%	45.0%	50.1%	47.2%	47.2%	47.0%	*49.5%*	*50.0%*	Long-Term Debt Ratio	*48.5%*
38.0%	37.7%	44.6%	47.8%	50.1%	55.0%	49.9%	52.8%	52.8%	53.0%	*50.5%*	*50.0%*	Common Equity Ratio	*51.5%*
1154.8	1180.8	1026.5	1001.3	998.6	877.8	988.2	1039.6	1031.5	869.2	*930*	*965*	Total Capital ($mill)	*1030*
1273.6	1226.4	521.5	550.7	546.4	517.1	548.8	563.9	592.1	647.0	*830*	*870*	Net Plant ($mill)	*810*
6.7%	5.4%	7.1%	7.9%	8.1%	7.3%	4.3%	4.5%	4.1%	6.5%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
9.3%	8.4%	10.3%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.5%*
10.4%	9.4%	11.4%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	*9.5%*	*10.0%*	Return on Com Equity D	*10.5%*
1.2%	.4%	2.5%	4.0%	3.8%	.6%	NMF	NMF	NMF	NMF	*.5%*	*1.0%*	Retained to Com Eq	*2.0%*
89%	96%	78%	68%	68%	93%	NMF	112%	NMF	117%	*93%*	*89%*	All Div'ds to Net Prof	*80%*

ELECTRIC OPERATING STATISTICS

	2004	2005	2006
% Change Retail Sales (KWH)	+3.3	+2.6	-3.1
Avg. Indust. Use (MWH)	639	665	657
Avg. Indust. Revs. per KWH (¢)	9.13	9.70	10.2
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.1	Nil	Nil
Fixed Charge Cov. (%)	375	263	323

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.0%	3.0%	*3.0%*
"Cash Flow"	-1.0%	-5.0%	*9.0%*
Earnings	-2.5%	-8.5%	*5.5%*
Dividends	--	--	*Nil*
Book Value	1.5%	1.0%	*-1.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	249.4	260.7	323.4	267.8	1101.3
2005	278.5	279.9	369.4	285.3	1213.1
2006	200.3	199.8	261.1	184.8	846.0
2007	274.6	*240*	*300*	*225.4*	*1040*
2008	*300*	*265*	*325*	*250*	*1140*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.24	.43	.68	.19	1.54
2005	.13	.14	.77	.26	1.30
2006	.15	.42	1.21	.08	1.86
2007	.22	*.45*	*.93*	*.25*	*1.85*
2008	*.22*	*.48*	*.98*	*.27*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.432	.432	.432	.432	1.73
2004	.432	.432	.432	.432	1.73
2005	.432	.432	.432	.432	1.73
2006	.432	.432	.432	.432	1.73
2007	.432	.432			

BUSINESS: UIL Holdings, parent of The United Illuminating Company, provides electricity to 320,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 46%; commer, 41%; indust, 11%; other, 2%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. 2004, sold American Payment Systems. 2006, sold Xcelecom. Fuel costs: 49% of revenues; labor costs, 13%. '06 deprec. rate: 3.8%. Has 920 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Tel.: 203-499-2394. Internet: www.uil.com.

UIL Holdings and Connecticut L&P are building a 345-kilovolt transmission line to strengthen the grid. The 69-mile line, which will run between Middletown and Norwalk, will increase the inflow of power from out of state. The cost of the project rose from an original estimate of $600 million to $1.3 billion because of an agreement to construct 24 miles underground. UIL will have a 20% stake in the line, which is targeted to begin operations in the summer of 2009. Regulation permits the company to recover prudently incurred costs as work progresses. The balance will be recovered through rate requests. *In the early stages,* UIL will finance its share of the cost internally, later with short-term and long-term debt. The line will not only supply power to the two owners but will generate income by serving other New England utilities.

The company is upgrading its aging infrastructure. A majority of operating assets were installed in the 1960s and 1970s. Their average useful lives range from 35 to 50 years. Some 81% of substations are now more than 30 years old, and their reliability is diminishing. To insure that equipment exceeds acceptable standards, UIL plans capital expenditures of $1.75 billion over the next 10 years. Regulation which permits ongoing recovery of 50% of prudently incurred costs will ease the financial burden somewhat. The balance must be recouped through rates.

Earnings may only mark time this year. Pluses include higher retail energy sales, improved pricing, and an electric rate increase of $4.3 million. But an IRS letter authorizing a one-time tax credit of $0.26 a share taken in the third quarter of 2006 will offset these positives. For now, we estimate current-year earnings of $1.85 a share. Higher rates of $4.3 million suggest modest improvement in 2008. The stock is untimely.

The share price has declined about 15% since our report six months ago. *That's attributable, in our opinion, to additional losses associated with Xcelecom as a result of a further review.* (Our earnings presentation excludes these charges because of their nonrecurring nature.) At the stock's recent quote, UIL is an average long-term utility holding.

Arthur H. Medalie *June 1, 2007*

(A) EPS basic. Excl. nonrecur. gains (losses): '91, 27¢; '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, net 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due late July. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '06: 77¢/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '06: 9.75%. Earned on average common equity in '06: 9.0%. Regul. Clim.: Below Average. (E) In millions.

Company's Financial Strength	B+
Stock's Price Stability	75
Price Growth Persistence	70
Earnings Predictability	60

ATTACHMENT B

ZACKS
PROFIT FROM THE PROS

Zacks.com Quotes and Research

CH ENERGY GRP HLDG (NYSE)

Scottrade

CHG	44.10	▼-0.46	(-1.03%)	Vol. 20,700	13:56 ET

CENTRAL HUDSON GAS & ELECTRIC generates, purchases and distributes electricity and purchases and distributes gas. The Company, in the opinion of its general counsel, has, with minor exceptions, valid franchises, unlimited in duration, to serve a territory extending about 85 miles along the Hudson River and about 25 to 40 miles east and west from such River. The southern end of the territory is about 25 miles north of New York City, and the northern end is about 10 miles south of the City of Albany.

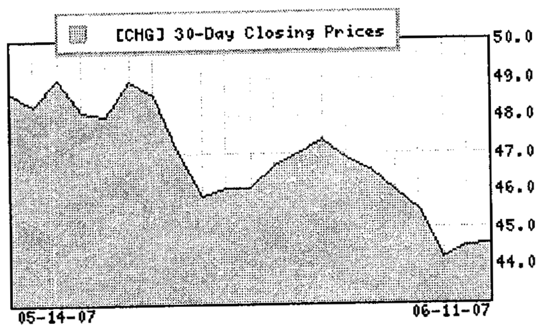
General Information

CH ENERGY GRP
284 South Avenue
Poughkeepsie, NY 12601-4879
Phone: 845 452-2000
Fax: 914 486-5415
Web: www.chenergygroup.com
Email: customerservices@cenhud.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	07/24/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	44.56
52 Week High	53.76
52 Week Low	45.18
Beta	0.48
20 Day Moving Average	64,250.00
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-5.25	4 Week	-6.01
12 Week	-3.21	12 Week	-9.67

YTD	-13.18	YTD	-15.33
Share Information		**Dividend Information**	
Shares Outstanding (millions)	15.76	Dividend Yield	4.71%
		Annual Dividend	$2.16
Market Capitalization (millions)	722.53	Payout Ratio	0.73
Short Ratio	23.20	Change in Payout Ratio	-0.10
Last Split Date	N/A	Last Dividend Payout / Amount	04/05/2007 / $0.54

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	N/A
Current Year EPS Consensus Estimate	2.67	30 Days Ago	N/A
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	N/A
Next EPS Report Date	07/24/2007	90 Days Ago	N/A

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	17.14	vs. Previous Year	18.10%	vs. Previous Year	8.24%
Trailing 12 Months:	15.54	vs. Previous Quarter	120.97%	vs. Previous Quarter:	54.36%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.41	03/31/07	9.03	03/31/07	3.27
Price/Cash Flow	9.17	12/31/06	8.42	12/31/06	3.08
Price / Sales	0.71	09/30/06	8.83	09/30/06	3.26
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	1.68	03/31/07	1.55	03/31/07	4.56
12/31/06	1.39	12/31/06	1.25	12/31/06	4.34
09/30/06	1.36	09/30/06	1.19	09/30/06	4.33
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	6.98	03/31/07	6.98	03/31/07	33.41
12/31/06	6.81	12/31/06	6.81	12/31/06	32.54
09/30/06	7.02	09/30/06	7.02	09/30/06	32.47
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	25.17	03/31/07	0.70	03/31/07	41.42
12/31/06	22.59	12/31/06	0.66	12/31/06	38.86

09/30/06	24.35	09/30/06	0.61	09/30/06	36.96

ZACKS
PROFIT FROM THE PROS

Zacks.com Quotes and Research

CLECO CP(HLDG CO) (NYSE)

Scottrade

CNL	25.20	▼-0.05	(-0.20%)	Vol. 98,500	14:01 ET

Cleco Corporation holds investments in several subsidiaries, including Utility Group, Cleco Midstream Resources LLC and Utility Construction & Technology Solutions LLC. Utility Group, incorporated on January 2, 1935 under the laws of the State of Louisiana, contains the LPSC jurisdictional generation, transmission and distribution electric utility operations serving the Company's traditional retail and wholesale customers. Utility Group serves customers in communities and rural areas in the State of Louisiana.

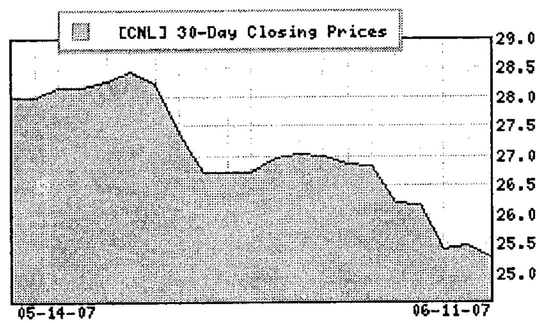
General Information

CLECO CORP
2030 Donahue Ferry Road
Pineville, LA 71360-5226
Phone: 318 484-7400
Fax: 318 484-7465
Web: www.cleco.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.25
52 Week High	29.01
52 Week Low	21.64
Beta	1.39
20 Day Moving Average	505,829.25
Target Price Consensus	27.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.89	4 Week	-8.63
12 Week	1.98	12 Week	-4.83

YTD	5.91	YTD	4.44
Share Information		**Dividend Information**	
Shares Outstanding (millions)	57.68	Dividend Yield	3.37%
		Annual Dividend	$0.90
Market Capitalization (millions)	1,541.21	Payout Ratio	0.72
Short Ratio	8.53	Change in Payout Ratio	0.00
Last Split Date	05/22/2001	Last Dividend Payout / Amount	04/26/2007 / $0.44

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.26	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.30	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	12.00	60 Days Ago	2.75
Next EPS Report Date	08/09/2007	90 Days Ago	2.75

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	20.55	vs. Previous Year	-39.13%	vs. Previous Year	0.15%
Trailing 12 Months:	21.38	vs. Previous Quarter	-22.22%	vs. Previous Quarter:	-3.64%
PEG Ratio	1.71				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.75	03/31/07	8.47	03/31/07	3.53
Price/Cash Flow	20.57	12/31/06	9.47	12/31/06	3.85
Price / Sales	1.54	09/30/06	8.83	09/30/06	2.95
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	1.20	03/31/07	0.94	03/31/07	7.10
12/31/06	7.77	12/31/06	1.18	12/31/06	7.46
09/30/06	1.45	09/30/06	1.24	09/30/06	6.30
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	7.16	03/31/07	7.16	03/31/07	15.48
12/31/06	-	12/31/06	-	12/31/06	15.24
09/30/06	27.75	09/30/06	27.75	09/30/06	15.59
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-0.37	03/31/07	0.69	03/31/07	40.93
12/31/06	0.00	12/31/06	0.11	12/31/06	10.04

09/30/06	11.67	09/30/06	0.66	09/30/06	39.34

Zacks.com Quotes and Research

HAWAIIAN ELEC INDS (NYSE)

Scottrade

HE	23.44	▼-0.11	(-0.47%)	Vol. 132,400	14:08 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

General Information

HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
Phone: 808 543-5662
Fax: 808 543-7966
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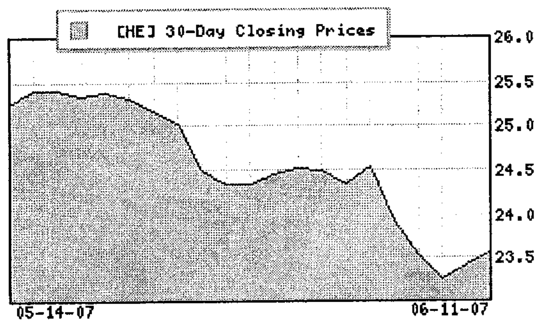
Email: shollinger@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/07/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	23.55
52 Week High	28.93
52 Week Low	24.50
Beta	0.48
20 Day Moving Average	342,402.56
Target Price Consensus	25.6



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.30	4 Week	-8.05
12 Week	-6.38	12 Week	-12.63
YTD	-9.76	YTD	-12.97

Share Information		Dividend Information	
Shares Outstanding (millions)	81.47	Dividend Yield	5.06%
		Annual Dividend	$1.24
Market Capitalization (millions)	1,996.04	Payout Ratio	1.13
Short Ratio	23.75	Change in Payout Ratio	0.00
Last Split Date	06/14/2004	Last Dividend Payout / Amount	02/22/2007 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.33	Current (1=Strong Buy, 5=Strong Sell)	3.50
Current Year EPS Consensus Estimate	1.26	30 Days Ago	3.33
Estimated Long-Term EPS Growth Rate	4.90	60 Days Ago	3.33
Next EPS Report Date	08/07/2007	90 Days Ago	3.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.47	vs. Previous Year	-57.50%	vs. Previous Year	-3.64%
Trailing 12 Months:	22.27	vs. Previous Quarter	-15.00%	vs. Previous Quarter:	-8.74%
PEG Ratio	3.99				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.82	03/31/07	7.71	03/31/07	0.90
Price/Cash Flow	7.67	12/31/06	9.10	12/31/06	1.09
Price / Sales	0.82	09/30/06	10.63	09/30/06	1.30
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	0.66	03/31/07	0.66	03/31/07	3.66
12/31/06	0.26	12/31/06	0.26	12/31/06	4.39
09/30/06	0.25	09/30/06	0.25	09/30/06	5.22
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	5.25	03/31/07	5.25	03/31/07	13.46
12/31/06	6.95	12/31/06	6.95	12/31/06	13.46
09/30/06	8.28	09/30/06	8.28	09/30/06	15.23
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	1.12	03/31/07	53.46
12/31/06	-	12/31/06	1.03	12/31/06	50.08
09/30/06	-	09/30/06	0.92	09/30/06	48.53

Zacks.com Quotes and Research

MGE ENERGY INC. (NASDAQ)				Scottrade	
MGEE	31.74	▼-0.66	(-2.04%)	Vol. 94,298	16:00 ET

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

General Information

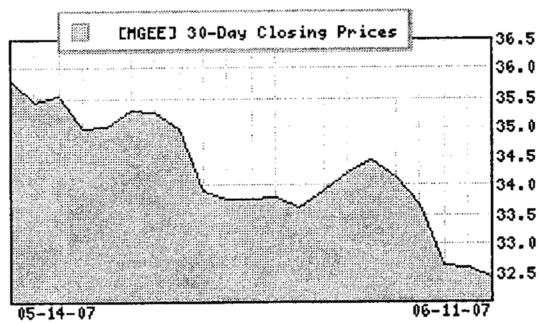
MGE ENERGY INC
133 South Blair St
Madison, WI 53703
Phone: 608 252-7000
Fax: 608 252-7098
Web: www.mge.com
Email: investor@mgeenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	N/A

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.40
52 Week High	37.00
52 Week Low	29.28
Beta	0.54
20 Day Moving Average	56,889.80
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-8.38	4 Week	-9.11
12 Week	1.47	12 Week	-5.31

YTD	-7.33	YTD	-10.86
Share Information		**Dividend Information**	
Shares Outstanding (millions)	20.99	Dividend Yield	4.11%
		Annual Dividend	$1.39
Market Capitalization (millions)	711.66	Payout Ratio	0.67
Short Ratio	23.77	Change in Payout Ratio	0.00
Last Split Date	02/21/1996	Last Dividend Payout / Amount	02/27/2007 / $0.35

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	N/A	Current (1=Strong Buy, 5=Strong Sell)	N/A
Current Year EPS Consensus Estimate	N/A	30 Days Ago	N/A
Estimated Long-Term EPS Growth Rate	N/A	60 Days Ago	N/A
Next EPS Report Date	N/A	90 Days Ago	N/A

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	-	vs. Previous Year	5.36%	vs. Previous Year	5.86%
Trailing 12 Months:	16.22	vs. Previous Quarter	9.26%	vs. Previous Quarter:	21.12%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.02	03/31/07	11.81	03/31/07	4.61
Price/Cash Flow	11.21	12/31/06	12.01	12/31/06	4.65
Price / Sales	1.38	09/30/06	11.34	09/30/06	4.36
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	0.99	03/31/07	0.75	03/31/07	8.36
12/31/06	-	12/31/06	-	12/31/06	8.36
09/30/06	0.80	09/30/06	0.46	09/30/06	7.53
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	-	03/31/07	-	03/31/07	18.39
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	12.13	09/30/06	12.13	09/30/06	17.54
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	0.61	03/31/07	38.07
12/31/06	-	12/31/06	-	12/31/06	-

09/30/06	6.23	09/30/06	0.58	09/30/06	36.51

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Zacks.com Quotes and Research

Scottrade

NORTHEAST UTIL (NYSE)

NU	28.14	▼-0.36	(-1.26%)	Vol. 935,200

16:01 ET

Northeast Utilities is the parent company of the Northeast Utilitiessystem. The Northeast Utilities system furnishes franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through three of the company's wholly owned subsidiaries: The Connecticut Light and Power Company; Public Service Company of New Hampshire; and Western Massachusetts Electric Company. It also provides service to a limited number of customers through another wholly owned subsidiary, Holyoke Water Power Company.

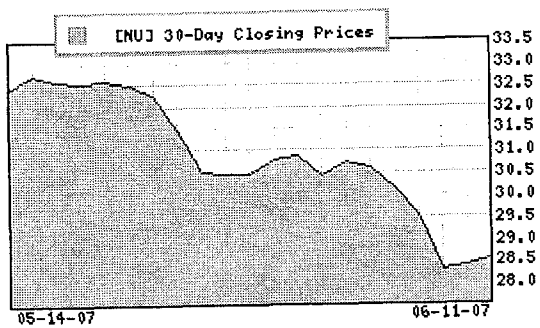
General Information

NORTHEAST UTIL
One Federal Street
Building 111-4
Springfield, MA 01105
Phone: 413 785-5871
Fax: 413 665-3652
Web: www.nu.com
Email: psnhreq@psnh.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	28.50
52 Week High	33.53
52 Week Low	19.36
Beta	0.42
20 Day Moving Average	890,615.88
Target Price Consensus	30.75



% Price Change

4 Week -7.97

% Price Change Relative to S&P 500

4 Week -8.70

12 Week	5.03	12 Week	-1.99
YTD	8.31	YTD	7.76
Share Information		**Dividend Information**	
Shares Outstanding (millions)	154.29	Dividend Yield	2.46%
		Annual Dividend	$0.75
Market Capitalization (millions)	4,705.69	Payout Ratio	0.65
Short Ratio	4.20	Change in Payout Ratio	0.08
Last Split Date	N/A	Last Dividend Payout / Amount	02/27/2007 / $0.19

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.25	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.43	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	13.00	60 Days Ago	3.00
Next EPS Report Date	08/09/2007	90 Days Ago	2.60

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	21.33	vs. Previous Year	44.12%	vs. Previous Year	-20.63%
Trailing 12 Months:	26.52	vs. Previous Quarter	36.11%	vs. Previous Quarter:	14.91%
PEG Ratio	1.64				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.68	03/31/07	6.75	03/31/07	1.56
Price/Cash Flow	7.32	12/31/06	6.12	12/31/06	1.32
Price / Sales	0.73	09/30/06	5.91	09/30/06	1.20
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	1.80	03/31/07	1.63	03/31/07	2.73
12/31/06	1.27	12/31/06	1.14	12/31/06	2.22
09/30/06	1.36	09/30/06	1.25	09/30/06	1.95
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	3.07	03/31/07	3.07	03/31/07	18.26
12/31/06	0.73	12/31/06	0.73	12/31/06	18.17
09/30/06	-0.22	09/30/06	-0.22	09/30/06	16.08
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	26.94	03/31/07	1.54	03/31/07	61.31

12/31/06	29.99	12/31/06	1.48	12/31/06	59.66
09/30/06	30.29	09/30/06	1.69	09/30/06	63.51

Zacks.com Quotes and Research

NSTAR (NYSE)

NST	32.67	▼-0.43	(-1.30%)	Vol. 315,400	16:03 ET

NSTAR was formed through a merger of BEC Energy and Commonwealth Energy System. The company, headquartered in Boston, Massachusetts provides regulated electric and gas utility services and is also engaged intelecommunications and other non-regulated activities. NSTAR, through its subsidiaries, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company, serves approximately 1.3 million customers throughout Massachusetts. (Press Release)

General Information

NSTAR
800 Boylston Street
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Phone: 617 424-2000
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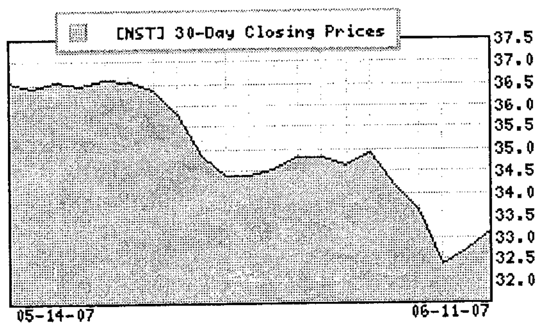
Web: www.nstaronline.com
Email: ir@nstar.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	07/26/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.10
52 Week High	37.27
52 Week Low	27.15
Beta	0.51
20 Day Moving Average	296,505.00
Target Price Consensus	37



% Price Change

4 Week	-6.39
12 Week	1.99

% Price Change Relative to S&P 500

4 Week	-7.14
12 Week	-4.82

YTD	1.54	YTD	-0.81
Share Information		**Dividend Information**	
Shares Outstanding (millions)	106.81	Dividend Yield	3.73%
		Annual Dividend	$1.30
Market Capitalization (millions)	3,726.53	Payout Ratio	0.66
Short Ratio	8.84	Change in Payout Ratio	0.01
Last Split Date	06/06/2005	Last Dividend Payout / Amount	04/05/2007 / $0.32
EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.44	Current (1=Strong Buy, 5=Strong Sell)	2.29
Current Year EPS Consensus Estimate	2.09	30 Days Ago	2.29
Estimated Long-Term EPS Growth Rate	6.30	60 Days Ago	2.00
Next EPS Report Date	07/26/2007	90 Days Ago	2.33

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.67	vs. Previous Year	9.76%	vs. Previous Year	-4.87%
Trailing 12 Months:	17.62	vs. Previous Quarter	18.42%	vs. Previous Quarter:	22.73%
PEG Ratio	2.67				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.35	03/31/07	13.26	03/31/07	2.74
Price/Cash Flow	6.53	12/31/06	13.29	12/31/06	2.69
Price / Sales	1.06	09/30/06	13.28	09/30/06	2.68
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	0.76	03/31/07	0.72	03/31/07	5.97
12/31/06	0.77	12/31/06	0.67	12/31/06	5.78
09/30/06	0.78	09/30/06	0.68	09/30/06	5.72
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	9.38	03/31/07	9.38	03/31/07	15.40
12/31/06	9.12	12/31/06	9.12	12/31/06	14.82
09/30/06	7.03	09/30/06	7.03	09/30/06	14.82
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	19.26	03/31/07	1.05	03/31/07	51.15
12/31/06	19.45	12/31/06	1.49	12/31/06	59.87

09/30/06	20.86	09/30/06	1.09	09/30/06	52.74

Zacks.com Quotes and Research

PUGET ENERGY HOLDING (NYSE)

PSD	24.00	▾-0.33	(-1.36%)	Vol. 627,800	16:04 ET

Puget Sound Energy, Incorporated is an investor-owned public utility that furnishes electric and gas service. The company conducts its business principally in the Puget Sound region of Washington state. PSE is on the forefront of the future. Innovative programs such as the PSE EnergyTracker are helping to make them the best energy distribution company anywhere, bar none. It's part of an ongoing promise: to offer their customers, community and shareholders unparalleled value in the 21st century.

General Information

PUGET ENERGY
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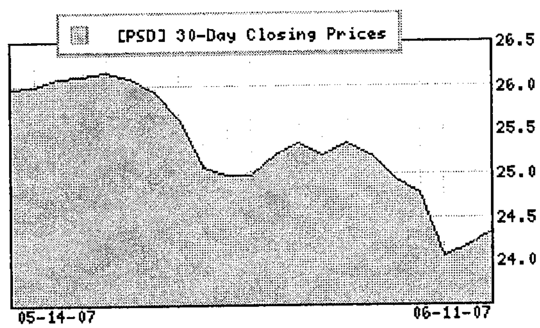
Suite 1200
Bellevue, WA 98004-5591
Phone: 425 454-6363
Fax: 425 462-3300
Web: www.pse.com
Email: investor@pse.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.33
52 Week High	26.80
52 Week Low	20.47
Beta	0.38
20 Day Moving Average	479,450.00
Target Price Consensus	27.2



% Price Change

4 Week -5.54

% Price Change Relative to S&P 500

4 Week -6.29

12 Week	1.66	12 Week	-5.13
YTD	-1.10	YTD	-3.96

Share Information		**Dividend Information**	
Shares Outstanding (millions)	116.72	Dividend Yield	3.99%
		Annual Dividend	$1.00
Market Capitalization (millions)	2,927.41	Payout Ratio	0.67
Short Ratio	4.76	Change in Payout Ratio	-0.09
Last Split Date	N/A	Last Dividend Payout / Amount	04/18/2007 / $0.25

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.26	Current (1=Strong Buy, 5=Strong Sell)	2.60
Current Year EPS Consensus Estimate	1.61	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.60
Next EPS Report Date	08/09/2007	90 Days Ago	3.00

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	15.54	vs. Previous Year	6.25%	vs. Previous Year	14.37%
Trailing 12 Months:	16.83	vs. Previous Quarter	38.78%	vs. Previous Quarter:	7.45%
PEG Ratio	3.88				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.38	03/31/07	8.15	03/31/07	2.57
Price/Cash Flow	6.80	12/31/06	7.90	12/31/06	2.49
Price / Sales	0.97	09/30/06	8.03	09/30/06	2.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	-	03/31/07	-	03/31/07	5.70
12/31/06	0.77	12/31/06	0.62	12/31/06	5.76
09/30/06	-	09/30/06	-	09/30/06	5.94
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	8.94	12/31/06	8.94	12/31/06	18.18
09/30/06	-	09/30/06	-	09/30/06	-
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	-	03/31/07	-

12/31/06	14.61	12/31/06	1.23	12/31/06	55.54
09/30/06	-	09/30/06	-	09/30/06	-

Zacks.com Quotes and Research

UIL HLDGS CP (NYSE)

Scottrade

UIL	32.11	▼-0.45	(-1.38%)	Vol. 172,800	16:02 ET

UIL Holdings Corporation is the holding company for The United Illuminating Company and United Resources. United Illuminating Company is aNew Haven-based regional distribution utility that provides electricity and energy-related services to customers in municipalities in the Greater New Haven and Greater Bridgeport areas.(PR)

General Information

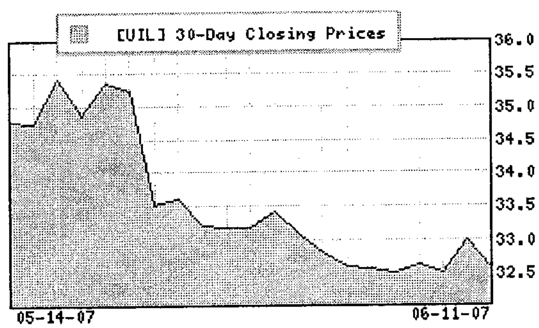
UIL HOLDINGS CP
157 Church Street
New Haven, CT 06506
Phone: 203 499-2000
Fax: 203 499-2414
Web: www.uil.com
Email: Susan.Allen@uinet.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	03/31/07
Next EPS Date	08/08/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.56
52 Week High	43.44
52 Week Low	32.43
Beta	0.84
20 Day Moving Average	183,370.00
Target Price Consensus	37



% Price Change

4 Week	-5.84
12 Week	-8.87
YTD	-21.31

% Price Change Relative to S&P 500

4 Week	-6.60
12 Week	-14.95
YTD	-21.94

Share Information		Dividend Information	
Shares Outstanding (millions)	25.06	Dividend Yield	5.20%
		Annual Dividend	$1.73
Market Capitalization (millions)	831.93	Payout Ratio	1.17
Short Ratio	8.37	Change in Payout Ratio	0.00
Last Split Date	07/05/2006	Last Dividend Payout / Amount	03/02/2007 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.41	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.99	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	08/08/2007	90 Days Ago	3.00

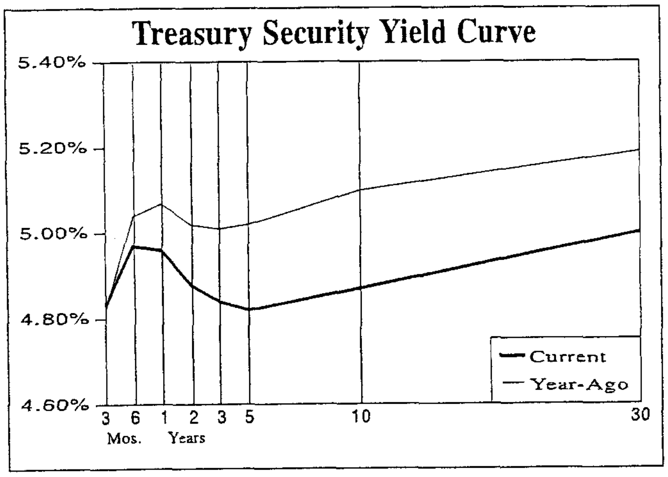
Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.68	vs. Previous Year	115.69%	vs. Previous Year	-8.01%
Trailing 12 Months:	22.43	vs. Previous Quarter	175.00%	vs. Previous Quarter:	-%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.78	03/31/07	7.66	03/31/07	2.20
Price/Cash Flow	5.89	12/31/06	6.87	12/31/06	1.97
Price / Sales	-	09/30/06	7.33	09/30/06	2.16
Current Ratio		**Quick Ratio**		**Operating Margin**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	1.29	12/31/06	1.28	12/31/06	-
09/30/06	-	09/30/06	-	09/30/06	3.59
Net Margin		**Pre-Tax Margin**		**Book Value**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	10.00	12/31/06	10.00	12/31/06	18.66
09/30/06	-	09/30/06	-	09/30/06	-
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
03/31/07	-	03/31/07	-	03/31/07	-
12/31/06	110.75	12/31/06	0.89	12/31/06	47.01
09/30/06	-	09/30/06	-	09/30/06	-

ATTACHMENT C

Selected Yields

	Recent (5/30/07)	3 Months Ago (2/28/07)	Year Ago (6/01/06)
TAXABLE			
Market Rates			
Discount Rate	6.25	6.25	6.00
Federal Funds	5.25	5.25	5.00
Prime Rate	8.25	8.25	8.00
30-day CP (A1/P1)	5.23	5.23	5.00
3-month LIBOR	5.36	5.35	5.27
Bank CDs			
6-month	3.10	3.28	3.07
1-year	3.72	3.88	3.88
5-year	3.91	3.92	4.04
U.S. Treasury Securities			
3-month	4.83	5.12	4.82
6-month	4.97	5.11	5.04
1-year	4.96	4.93	5.07
5-year	4.82	4.52	5.02
10-year	4.87	4.57	5.10
10-year (inflation-protected)	2.52	2.19	2.43
30-year	5.00	4.68	5.19
30-year Zero	4.97	4.61	5.08



	Recent (5/30/07)	3 Months Ago (2/28/07)	Year Ago (6/01/06)
Mortgage-Backed Securities			
GNMA 6.5%	5.79	5.63	6.03
FHLMC 6.5% (Gold)	5.97	5.73	6.24
FNMA 6.5%	5.92	5.63	6.20
FNMA ARM	5.50	5.60	4.95
Corporate Bonds			
Financial (10-year) A	5.84	5.38	6.04
Industrial (25/30-year) A	5.96	5.62	6.25
Utility (25/30-year) A	6.18	5.65	6.25
Utility (25/30-year) Baa/BBB	6.31	5.89	6.62
Foreign Bonds (10-Year)			
Canada	4.48	4.03	4.40
Germany	4.40	3.96	4.00
Japan	1.74	1.64	1.95
United Kingdom	5.24	4.80	4.64
Preferred Stocks			
Utility A	7.29	7.22	7.23
Financial A	6.39	6.35	6.32
Financial Adjustable A	5.53	5.53	N/A
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.38	4.19	4.57
25-Bond Index (Revs)	4.55	4.48	5.23
General Obligation Bonds (GOs)			
1-year Aaa	3.63	3.56	3.52
1-year A	3.73	3.66	3.63
5-year Aaa	3.74	3.55	3.67
5-year A	3.85	3.64	3.91
10-year Aaa	3.89	3.67	4.07
10-year A	4.39	4.20	4.35
25/30-year Aaa	4.24	3.97	4.53
25/30-year A	4.54	4.28	4.78
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.63	4.39	4.60
Electric AA	4.57	4.38	4.59
Housing AA	4.81	4.44	4.73
Hospital AA	4.80	4.45	4.83
Toll Road Aaa	4.65	4.39	4.80

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/23/07	5/9/07	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1297	1470	-173	1563	1597	1623
Borrowed Reserves	113	71	42	69	118	205
Net Free/Borrowed Reserves	1184	1399	-215	1494	1480	1418

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/14/07	5/7/07	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1366.9	1372.6	-5.7	1.4%	0.9%	-1.5%
M2 (M1+savings+small time deposits)	7226.2	7228.1	-1.9	7.2%	7.7%	6.5%

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-06-0783
TABLE OF CONTENTS TO SCHEDULES WAR

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
COST OF CAPITAL SUMMARY

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 1
PAGE 1 OF 3

WEIGHTED COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) CAPITAL RATIO	(C) RUCO COST	(D) WEIGHTED COST
1	SHORT-TERM DEBT	$ 5,000	3.97%	6.36%	0.25%
2	LONG-TERM DEBT	59,486	47.18%	8.22%	3.88%
3	COMMON EQUITY	61,587	48.85%	9.30%	4.54%
4	TOTAL CAPITALIZATION	$ 126,073	100.00%		
5	**WEIGHTED COST OF CAPITAL**				8.67%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): COLUMN (B) ÷ COLUMN (A), LINE 4
COLUMN (C): LINE 1 - SCHEDULE WAR-1, PAGE 2, LINE 6
LINE 2 - SCHEDULE WAR-1, PAGE 2, LINE 9
LINE 2 - SCHEDULE WAR-1, PAGE 3, LINE 7
COLUMN (D): COLUMN (B) x COLUMN (C)

COST OF LONG AND SHORT-TERM DEBT

LINE NO.	(A) DESCRIPTION	(B) OUTSTANDING BALANCE	(C) ANNUAL INTEREST	(D) INTEREST RATE
1	UNS ELECTRIC SENIOR NOTE	$ 60,000	$ 4,566	7.610%
2	LESS: UNAMORTIZED DEBT DISCOUNT, PREMIUM AND EXPENSE AND LOSS ON REAQUIRED DEBT	514		
3	ADD: AMORTIZATION OF DEBT DISCOUNT AND EXPENSE AND LOSS ON REAQUIRED DEBT		278	
4	ADD: CREDIT FACILITY COMMITMENT FEES		45	
5	TOTAL LONG-TERM DEBT - NET	$ 59,486	$ 4,889	
6	**COST OF LONG-TERM DEBT - NET**			8.22%
7	UNS SHORT-TERM DEBT	$ 5,000	$ 318	
8	TOTAL SHORT-TERM DEBT	$ 5,000	$ 318	
9	**COST OF SHORT-TERM DEBT**			6.36%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (B): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (C): COMPANY SCHEDULE D-2, PAGE 1
COLUMN (D): COLUMN (C) ÷ COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	7.89%	SCHEDULE WAR-2, COLUMN (C), LINE 9
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	9.85%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 9
5	CAPM - ARITHMETIC MEAN ESTIMATE	11.56%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 9
6	AVERAGE OF CAPM ESTIMATES	10.70%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE**	9.30%	(LINE 2 + LINE 6) ÷ 2

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	CHG	CH ENERGY GROUP	4.52%	+	2.70%	=	7.22%
2	CNL	CLECO CORPORATION	3.24%	+	3.77%	=	7.01%
3	HE	HAWAIIAN ELECTRIC	4.88%	+	4.22%	=	9.10%
4	MGEE	MGE ENERGY, INC.	3.93%	+	4.30%	=	8.24%
5	NU	NORTHEAST UTILITIES	2.51%	+	4.08%	=	6.60%
6	NST	NSTAR	3.62%	+	6.01%	=	9.62%
7	PSD	PUGET ENERGY, INC.	3.87%	+	3.94%	=	7.81%
8	UIL	UIL HOLDINGS	5.04%	+	2.52%	=	7.56%
9	**AVERAGE**						7.89%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND YIELD CALCULATION

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	CHG	CH ENERGY GROUP	$2.16	÷	$47.83	=	4.52%
2	CNL	CLECO CORPORATION	0.90	÷	27.75	=	3.24%
3	HE	HAWAIIAN ELECTRIC	1.24	÷	25.40	=	4.88%
4	MGEE	MGE ENERGY, INC.	1.39	÷	35.39	=	3.93%
5	NU	NORTHEAST UTILITIES	0.80	÷	31.84	=	2.51%
6	NST	NSTAR	1.30	÷	35.95	=	3.62%
7	PSD	PUGET ENERGY, INC.	1.00	÷	25.83	=	3.87%
8	UIL	UIL HOLDINGS	1.73	÷	34.31	=	5.04%
9	**AVERAGE**						3.95%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 04/16/2007 TO 06/08/2007 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 4
PAGE 1 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	CHG	CH ENERGY GROUP	2.70%	+	0.00%	=	2.70%
2	CNL	CLECO CORPORATION	3.10%	+	0.67%	=	3.77%
3	HE	HAWAIIAN ELECTRIC	3.35%	+	0.87%	=	4.22%
4	MGEE	MGE ENERGY, INC.	4.30%	+	0.00%	=	4.30%
5	NU	NORTHEAST UTILITIES	3.65%	+	0.43%	=	4.08%
6	NST	NSTAR	6.00%	+	0.01%	=	6.01%
7	PSD	PUGET ENERGY, INC.	3.75%	+	0.19%	=	3.94%
8	UIL	UIL HOLDINGS	2.00%	+	0.52%	=	2.52%
11	**AVERAGE**						3.94%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	CHG	CH ENERGY GROUP	0.01%	x	{ [((1.45) + 1) ÷ 2] - 1 }	=	0.00%
2	CNL	CLECO CORPORATION	1.70%	x	{ [((1.78) + 1) ÷ 2] - 1 }	=	0.67%
3	HE	HAWAIIAN ELECTRIC	2.00%	x	{ [((1.87) + 1) ÷ 2] - 1 }	=	0.87%
4	MGEE	MGE ENERGY, INC.	0.01%	x	{ [((1.97) + 1) ÷ 2] - 1 }	=	0.00%
5	NU	NORTHEAST UTILITIES	1.27%	x	{ [((1.68) + 1) ÷ 2] - 1 }	=	0.43%
6	NST	NSTAR	0.01%	x	{ [((2.31) + 1) ÷ 2] - 1 }	=	0.01%
7	PSD	PUGET ENERGY, INC.	1.00%	x	{ [((1.37) + 1) ÷ 2] - 1 }	=	0.19%
8	UIL	UIL HOLDINGS	1.25%	x	{ [((1.84) + 1) ÷ 2] - 1 }	=	0.52%
9	**AVERAGE**						0.34%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	CHG	CH ENERGY GROUP	2002	-0.0189		7.10%		NMF	30.31	16.06	
2			2003	0.2230		9.10%		2.03%	30.80	15.76	
3			2004	0.1970		8.60%		1.69%	31.31	15.76	
4			2005	0.2313		8.80%		2.04%	31.97	15.76	
5			2006	0.1563		7.90%		1.23%	32.54	15.76	
6			GROWTH 2002 - 2006					1.75%	1.50%		-0.47%
7			2007	0.2000		8.00%		1.60%		15.76	0.00%
8			2008	0.2421		8.50%		2.06%		15.00	-2.44%
9			2010-12	0.3046		9.00%		2.74%	2.00%	15.00	-0.98%
10											
11	CNL	CLECO CORPORATION	2002	0.4079		13.10%		5.34%	11.77	47.04	
12			2003	0.2857		12.50%		3.57%	10.09	47.18	
13			2004	0.3182		11.90%		3.79%	10.83	49.62	
14			2005	0.3662		10.70%		3.92%	13.69	49.99	
15			2006	0.3382		8.50%		2.88%	15.05	58.00	
16			GROWTH 2002 - 2006					3.90%	4.00%		5.38%
17			2007	0.2800		8.00%		2.24%		59.00	1.72%
18			2008	0.3077		8.00%		2.46%		60.00	1.71%
19			2010-12	0.3143		10.00%		3.14%	6.50%	63.00	1.67%
20											
21	HE	HAWAIIAN ELECTRIC	2002	0.2346		11.30%		2.65%	14.21	73.62	
22			2003	0.2152		10.80%		2.32%	14.36	75.84	
23			2004	0.0882		8.90%		0.79%	15.01	80.69	
24			2005	0.1507		9.70%		1.46%	15.02	80.98	
25			2006	0.0677		9.90%		0.67%	13.44	81.46	
26			GROWTH 2002 - 2006					1.58%	2.00%		2.56%
27			2007	0.0462		9.50%		0.44%		83.50	2.50%
28			2008	0.1143		10.00%		1.14%		85.50	2.45%
29			2010-12	0.2914		12.00%		3.50%	0.50%	87.00	1.32%
30											
31	MGEE	MGE ENERGY, INC.	2002	0.2071		12.80%		2.65%	12.94	17.57	
32			2003	0.2105		11.60%		2.44%	14.34	18.34	
33			2004	0.2316		10.00%		2.32%	16.59	20.39	
34			2005	0.1274		9.30%		1.18%	16.81	20.45	
35			2006	0.3252		10.50%		3.42%	16.95	20.70	
36			GROWTH 2002 - 2006					2.40%	6.50%		4.18%
37			2007	0.3286		12.00%		3.94%		20.70	0.00%
38			2008	0.3500		12.00%		4.20%		20.70	0.00%
39			2010-12	0.4235		10.50%		4.45%	7.00%	20.70	0.00%

REFERENCES: RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007.
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	NU	NORTHEAST UTILITIES	2002	0.5093		6.30%		3.21%	17.33	127.56	
2			2003	0.5323		6.90%		3.67%	17.73	127.70	
3			2004	0.3077		5.10%		1.57%	17.80	129.03	
4			2005	0.3061		5.10%		1.56%	18.46	131.59	
5			2006	0.1098		4.30%		0.47%	18.14	154.23	
6			GROWTH 2002 - 2006					2.10%	3.00%		4.86%
7			2007	0.4429		7.00%		3.10%		156.20	1.28%
8			2008	0.4645		8.00%		3.72%		158.20	1.28%
9			2010-12	0.4556		8.00%		3.64%	3.50%	164.20	1.26%
10											
11	NST	NSTAR	2002	0.3669		13.80%		5.06%	12.25	106.07	
12			2003	0.3736		13.70%		5.12%	12.84	106.07	
13			2004	0.3580		13.10%		4.69%	13.52	106.55	
14			2005	0.5246		12.80%		6.71%	14.37	106.81	
15			2006	0.2021		13.10%		2.65%	14.82	106.81	
16			GROWTH 2002 - 2006					4.85%	2.50%		0.17%
17			2007	0.3512		13.50%		4.74%		106.81	0.00%
18			2008	0.3644		13.50%		4.92%		106.81	0.00%
19			2010-12	0.4167		15.00%		6.25%	5.50%	106.81	0.00%
20											
21	PSD	PUGET ENERGY, INC.	2002	0.0242		7.20%		0.17%	16.27	93.64	
22			2003	0.1803		7.00%		1.26%	16.71	99.07	
23			2004	0.2424		8.10%		1.96%	16.24	99.87	
24			2005	0.2958		7.20%		2.13%	17.52	115.70	
25			2006	0.3056		7.90%		2.41%	18.15	116.58	
26			GROWTH 2002 - 2006					1.59%	1.50%		5.63%
27			2007	0.3750		8.50%		3.19%		117.00	0.36%
28			2008	0.3939		8.50%		3.35%		117.75	0.50%
29			2010-12	0.4000		9.50%		3.80%	4.00%	124.25	1.28%
30											
31	UIL	UIL HOLDINGS	2002	0.0649		9.10%		0.59%	20.28	23.79	
32			2003	-0.3952		6.00%		NMF	20.65	23.86	
33			2004	-0.1234		6.70%		NMF	22.84	24.01	
34			2005	-0.3308		5.80%		NMF	22.39	24.32	
35			2006	0.0699		9.90%		0.69%	18.53	24.86	
36			GROWTH 2002 - 2006					0.64%	1.00%		1.11%
37			2007	0.0649		9.50%		0.62%		25.20	1.37%
38			2008	0.1128		10.00%		1.13%		25.40	1.08%
39			2010-12	0.1953		10.50%		2.05%	-1.00%	26.60	1.36%

REFERENCES:

COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
GROWTH RATE COMPARISON

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	CHG	2.70%	-	3.00%	1.00%	2.00%	-2.50%	-	1.50%	1.00%	4.83%	0.00%	1.79%
2	CNL	3.77%	12.00%	4.00%	4.00%	6.50%	1.00%	2.00%	4.00%	4.79%	-2.74%	0.00%	6.34%
3	HE	4.22%	4.90%	4.00%	-	0.50%	-1.00%	-	2.00%	2.08%	-4.81%	0.00%	-1.38%
4	MGEE	4.30%	-	6.00%	0.50%	7.00%	2.00%	1.00%	6.50%	3.83%	5.07%	0.92%	6.98%
5	NU	4.08%	13.00%	12.00%	6.50%	3.50%	-	16.50%	3.00%	9.08%	-6.65%	8.33%	1.15%
6	NST	6.01%	6.30%	8.50%	7.00%	5.50%	3.50%	3.00%	2.50%	5.19%	3.38%	9.53%	4.88%
7	PSD	3.94%	4.00%	6.00%	3.00%	4.00%	-4.50%	-11.50%	1.50%	0.36%	3.81%	-4.65%	2.77%
8	UIL	2.52%	-	5.50%	-	-1.00%	-8.50%	-	1.00%	-0.75%	0.13%	0.00%	-2.23%
9				6.13%	3.67%	3.50%	-1.43%	2.20%	2.75%		0.38%	1.77%	2.54%
10	AVERAGES	3.94%	8.04%		4.43%			1.17%		3.20%		1.56%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/30/2007, 05/11/2007 AND 06/01/2007

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	CHG	k	=	4.85%	+ [	0.85	x (	10.40%	-	4.85%)]	=	9.57%
2	CNL	k	=	4.85%	+ [	1.30	x (	10.40%	-	4.85%)]	=	12.06%
3	HE	k	=	4.85%	+ [	0.75	x (	10.40%	-	4.85%)]	=	9.01%
4	MGEE	k	=	4.85%	+ [	0.80	x (	10.40%	-	4.85%)]	=	9.29%
5	NU	k	=	4.85%	+ [	0.90	x (	10.40%	-	4.85%)]	=	9.85%
6	NST	k	=	4.85%	+ [	0.80	x (	10.40%	-	4.85%)]	=	9.29%
7	PSD	k	=	4.85%	+ [	0.85	x (	10.40%	-	4.85%)]	=	9.57%
8	UIL	k	=	4.85%	+ [	0.95	x (	10.40%	-	4.85%)]	=	10.12%
9	**AVERAGE**					0.90						9.85%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 05/04/2007 THROUGH 06/08/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	CHG	k	=	4.85%	+ [	0.85	x (	12.30%	-	4.85%)]	=	11.18%
2	CNL	k	=	4.85%	+ [	1.30	x (	12.30%	-	4.85%)]	=	14.53%
3	HE	k	=	4.85%	+ [	0.75	x (	12.30%	-	4.85%)]	=	10.44%
4	MGEE	k	=	4.85%	+ [	0.80	x (	12.30%	-	4.85%)]	=	10.81%
5	NU	k	=	4.85%	+ [	0.90	x (	12.30%	-	4.85%)]	=	11.56%
6	NST	k	=	4.85%	+ [	0.80	x (	12.30%	-	4.85%)]	=	10.81%
7	PSD	k	=	4.85%	+ [	0.85	x (	12.30%	-	4.85%)]	=	11.18%
8	UIL	k	=	4.85%	+ [	0.95	x (	12.30%	-	4.85%)]	=	11.93%
9	**AVERAGE**					0.90						11.56%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 05/04/2007 THROUGH 06/08/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2006 PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR, INC.'S STOCKS, BONDS, BILLS AND INFLATION: 2007 YEARBOOK.

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	7.49%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	4.25%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	5.49%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	3.90%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.20%	6.16%	4.16%	3.16%	3.17%	4.57%	5.38%	5.78%
17	2006	2.50%	3.30%	7.97%	5.97%	4.97%	4.83%	4.88%	5.94%	6.30%
18	CURRENT	2.60%	0.60%	8.25%	6.25%	5.25%	4.73%	4.88%	6.07%	6.21%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/08/2007
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/08/2007
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

UNS ELECTRIC, INC.
TEST YEAR ENDED JUNE 30, 2006
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-04204A-06-0783
SCHEDULE WAR - 9

LINE NO.		CHG	PCT.	CNL	PCT.	HE	PCT.	MGEE	PCT.		
1	DEBT	$ 337,889.0	38.8%	$ 669,341.0	42.8%	$ 1,309,457.0	53.7%	$ 237,284.0	38.7%		
2											
3	PREFERRED STOCK	21,027.0	2.4%	20,092.0	1.3%	34,293.0	1.4%	0.0	0.0%		
4											
5	COMMON EQUITY	512,862.0	58.8%	876,129.0	56.0%	1,095,240.0	44.9%	375,348.0	61.3%		
6											
7	TOTALS	$ 871,778.0	100%	$ 1,565,562.0	100%	$ 2,438,990.0	100%	$ 612,632.0	100%		
8											
9										ELECTRIC COMPANY SAMPLE	
10		NU	NST	NST	PCT.	PSD	PCT.	UIL	PCT.	AVERAGE	PCT.
11											
12	DEBT	$ 2,965,312.0	50.4%	$ 2,360,775.0	59.2%	$ 2,183,360.0	51.8%	$ 408,603.0	47.0%	$ 1,309,002.6	51.2%
13											
14	PREFERRED STOCK	116,200.0	2.0%	43,000.0	1.1%	1,889.0	0.0%	0.0	0.0%	$ 29,562.6	1.2%
15											
16	COMMON EQUITY	2,798,179.0	47.6%	1,582,563.0	39.7%	2,027,047.0	48.1%	460,581.0	53.0%	$ 1,215,993.6	47.6%
17											
18	TOTALS	$ 5,879,691.0	100%	$ 3,986,338.0	100%	$ 4,212,296.0	100%	$ 869,184.0	100%	$ 2,554,558.9	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

EXHIBIT
RUCO-14
Admitted

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-06-0783

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

August 24, 2007

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to UNS Electric Inc.'s ("UNS" or "Company") rebuttal testimony on RUCO's recommended rate of return on invested capital (which includes RUCO's recommended cost of debt and cost of common equity) for the Company's electric distribution operations in Mohave and Santa Cruz Counties.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on June 28, 2007, I filed direct testimony with the Arizona Corporation Commission ("ACC" or "Commission"). My direct testimony addressed the cost of capital issues that were raised in UNS' application requesting a permanent rate increase ("Application") based on a test year ended June 30, 2006.

...

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains five parts: the introduction that I have just presented; a summary of UNS' rebuttal testimony; a section on capital structure; a section on cost of debt; and a section on cost of equity capital.

Q. Have you made any revisions to the cost of capital recommendations that you presented in your direct testimony?

A. No, I have not.

SUMMARY OF UNS ELECTRIC, INC.'S REBUTTAL TESTIMONY

Q. Have you reviewed UNS' rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimony, filed on August 14, 2007, of Company witnesses James S. Pignatelli and Kentton C. Grant.

Q. Please summarize Mr. Pignatelli's rebuttal testimony.

A. Mr. Pignatelli's rebuttal testimony presents an overview of the rebuttal testimony filed by the Company's witnesses. His testimony also provides a summary of the cost of capital recommendations being made by the Company, RUCO and ACC Staff. Mr. Pignatelli presents the argument of Mr. Grant, the Company's cost of capital witness, that the lower recommended rates of return being recommended by both RUCO and ACC Staff are not sufficient or reasonable because they do not take into account the unique business risk and customer growth that UNS faces.

Mr. Pignatelli also presents the argument that neither RUCO's nor ACC Staff's cost of capital recommendations were based on the results of a cash flow analysis.

Q. Please summarize Mr. Grant's rebuttal testimony.

A. Mr. Grant's rebuttal testimony discusses in detail the arguments presented in Mr. Pignatelli's rebuttal testimony regarding the rate of return recommendations being made by RUCO and ACC Staff. Mr. Grant also argues that RUCO's and ACC Staff's recommended rates of return do not meet the cost of capital standards set forth in the Hope and Bluefield decisions cited in my direct testimony. Mr. Grant further expresses his belief that my cost of equity recommendation is too low as a result of the estimate that I obtained from my discounted cash flow ("DCF") analysis and explains why he believes that my growth estimates are unrealistic. In addition to his arguments directly related to cost of capital issues, Mr. Grant opines that both RUCO's and ACC Staff's recommendations not to include construction-work-in-progress ("CWIP") in rate base was the single largest factor in the lower level of rate relief being recommended by both of those parties to the case. RUCO's position on the CWIP issue will be addressed in the surrebuttal testimony of RUCO witness Marylee Diaz Cortez.

CAPITAL STRUCTURE

Q. Have you made any changes to your recommended capital structure for UNS Electric?

A. No, I have not. Mr. Grant and I are in agreement with my recommendation to adopt the Company-proposed capital structure which is comprised of 3.97 percent short-term debt, 47.18 percent long-term debt and 48.85 percent common equity.

Q. How does your recommended capital structure compare with the capital structure being recommended by ACC Staff?

A. ACC Staff's cost of capital witness, David C. Parcell, is recommending a slightly different capital structure comprised of 3.96 percent short-term debt, 47.21 percent long-term debt and 48.83 percent common equity.

COST OF DEBT

Q. Have you made any adjustments to your recommended costs of short-term and long-term debt?

A. No, I have not. Mr. Grant and I are also in agreement with my recommendations to adopt the Company-proposed costs of short-term and long-term debt.

...

Q. Briefly summarize the current positions of the parties to the case regarding cost of debt, cost of equity and weighted cost of capital.

A. To date, UNS, RUCO and ACC Staff ("the parties to the case") are in agreement on the Company proposed 6.36 percent cost of short-term debt. The parties to the case are currently recommending the following costs of long-term debt:

UNS	8.22%
ACC Staff	8.16%
RUCO	8.22%

In regard to the cost of common equity, the parties to the case are presently recommending the following:

UNS	11.80%
ACC Staff	10.00%
RUCO	9.30%

Mr. Parcell's 10.00 percent cost of common equity recommendation is the mid-point of his recommended range of 9.50 percent to 10.50 percent.

...

The weighted costs of capital being recommended by the parties to the case are as follows:

UNS	9.89%
ACC Staff	8.97%
RUCO	8.67%

As can be seen above, there is presently a 122 basis point difference between the Company-proposed 9.89 percent weighted cost of capital and RUCO's recommended weighted cost of capital of 8.67 percent. RUCO and ACC Staff's recommended costs of capital fall within 30 basis points of each other.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On August 7, 2007, the Federal Reserve decided not to increase or decrease the Federal Funds rate for the ninth straight time, and left its target rate unchanged at 5.25 percent.[1] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation will fail to moderate. However, within days of the Fed's decision to stand pat on rates, a

[1] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

borrowing crises, rooted in the recent deterioration of the market for U.S. subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[2] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal,[3] the Fed has presently used all of its tools to restore normalcy to the financial markets. If the markets fail to settle down, the Fed's only weapon left is to cut the Federal Funds rate – possibly before the next scheduled FOMC meeting on September 18, 2007. The article went on to state that, despite the Fed's concerns with inflation, traders in the futures market are now expecting the Fed to make quarter point cuts in the Federal Funds rate during the FOMC's September and October meetings, and expect the rate to drop a full 100 basis points to 4.25 percent by the end of the year. If the traders' forecasts are correct, the prime rate, which generally moves in lockstep with the Federal Funds rate, should also fall to 7.25 percent by the end of December, 2007.

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[2] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[3] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

Q. What is the current situation in regard to the yields on U.S. Treasury Instruments?

A. As can be seen in Attachment A, the short-term 91-day T-Bill rate, which I used as the risk-free rate of return in my capital asset pricing model ("CAPM") analysis, has fallen to 4.09 percent as of August 15, 2007, and is presently 94 basis points lower than the benchmark long-term 30-year T-Bond yield of 5.03 percent. The current yield of 4.09 percent is 76 basis points lower than the six-week average 91-day T-Bill rate of 4.85 percent that I used in my CAPM analysis.

Q. What would happen if you were to incorporate the lower recent 4.09 percent 91-day T-Bill rate in your CAPM model?

A. If I were to recalculate my CAPM estimates using the lower recent 4.09 percent T-Bill rate, my CAPM results would move in the direction of the estimates derived in my DCF model.

Q. Please address Mr. Grant's criticism that the growth rates used in your DCF model are problematic from the standpoint of market expectations.

A. Mr. Grant presents two arguments in regard to the growth rates used in my DCF model. His first argument states that investors expect a convergence of individual growth rates towards the industry average growth rate and that my growth rate estimates fail to take this into account. Mr. Grant's second argument states that my growth estimates are not in line with long-term inflation-adjusted estimates of U.S. gross domestic product ("GDP") which is the long-term growth component used in the multi-stage DCF model that he has relied on for his cost of equity estimation. Both arguments presented by Mr. Grant should be given no weight.

Q. Please explain why Mr. Grant's first argument regarding your growth rate estimates should not be afforded any weight.

A. Mr. Grant's first argument assumes that investors place their funds in an individual electric service provider's stock because they expect the individual electric service provider's growth rates to converge with the long-term average of the electric power industry. In other words, if you've seen one electric utility company stock, you've seen them all because you are investing in an industry as opposed to an individual utility. If his argument were true, then investors would be investing in the electric utility industry as a whole (i.e. through an investment vehicle such as a mutual fund) as opposed to investing in an individual electric utility company. His argument totally ignores the premise that rational investors place their funds in individual stocks because they feel comfortable with the dividend yields and the growth potentials offered by the individual electric utilities that they are investing in. I believe that rational investors also weigh other factors such as superior management, corporate culture and philosophy, and past records of performance when making their investment decisions.

If you subscribe to Mr. Grant's argument, then it would not make any difference which electric utility company you made an investment in since they will all eventually provide the same returns in growth. This begs the question as to why there is so much investor information available on individual companies or why the managements of publicly traded firms tout their ability to provide returns that will exceed industry averages.

Q. Please address Mr. Grant's second argument regarding your growth rate estimates.

A. Mr. Grant's second argument assumes that my growth rates are unrealistic because they do not take into consideration a long-term inflation-adjusted estimate of U.S. gross domestic product ("GDP"), which is a long-term growth component that he considered in developing the long-term growth rate used in his multi-stage DCF model. More to the point, I believe that Mr. Grant is suggesting that I should have used a multi-stage DCF model that uses a long-term inflation-adjusted estimate of U.S. GDP which is what the Federal Energy Regulatory Commission ("FERC") relies on in rate increase requests filed with that agency. If you subscribe to his inflation-adjustment argument then you have to believe that every individual electric utility company included in both mine and Mr. Grant's samples are going to have inflation-adjusted growth that mirrors the GDP of the entire U.S. economy into perpetuity. This in itself is a rather broad and unrealistic expectation. Professional analysts often have enough trouble making accurate projections of the near-term (i.e. one-year) earnings of the companies that they follow. It would be unrealistic to believe that projections that extend into perpetuity would be more accurate than the near-term projections. The growth estimates used in my DCF model are a balance of known historical 5-year growth figures and projected growth estimates over the next five-year period (i.e. 2007 through 2012). I believe that this is a reasonable horizon for future growth estimates, given the fact that utilities typically apply for rate relief within a three to five-year time frame.

Q. Are there any other reasons why you believe that Mr. Grant's second argument on your growth rate estimates is not realistic?

A. Yes. It is interesting to note that in the multi-stage DCF model adopted by the FERC, more emphasis is given to short-term growth expectations (i.e. the projected growth estimates over the next five-year period that I relied on for my DCF growth estimates) as opposed to inflation-adjusted estimates of future U.S. GDP growth. This can be seen in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment B):

> "**Return on Equity or Cost of Equity:** This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow (DCF) analysis of a proxy group of publicly held natural gas companies. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short-term growth estimates and the other long-

> term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long-term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk."

As stated in the excerpt above, the FERC multi-stage DCF model weighs short-term estimates, similar to the ones used in my single stage DCF model, by a factor of two-thirds based on the fact that they are more predictable and deserve more weight than long-term estimates such as the ones produced in the unweighted multi-stage DCF model that Mr. Grant has relied on.

Q. Are there other arguments that you have with Mr. Grant's arguments regarding inflation?

A. Yes. The cost of capital estimates that I have developed from my DCF model actually do take inflation into account given the fact that investor expectations regarding inflation are reflected in the prices of the individual stocks that were included in my sample. The investment community always reacts to news on inflation. Reports in the mainstream financial press about investors buying or selling stocks based on news on inflation are extremely common. In fact inflation related buying and selling of stocks often occurs after Federal Reserve meetings when statements by the FOMC explain why inflation was a factor in their decision to act on interest rates. As I stated in my direct testimony, the lower costs of capital that I have calculated are largely influenced by the prices of electric utility stocks which have been high as a result of increased investor demand for such stocks because of their higher dividends. This was pointed out in The Value Line Investment Survey quarterly update of electric utilities in the western region of the U.S. that was exhibited as Attachment A of my direct testimony.

Furthermore, I should point out that in reality, utility rates are not set in perpetuity. Unless they have agreed to do otherwise, such as in the case of a long-term rate moratorium like the one entered into by the Company's parent, regulated utilities always have the option of filing for rate increases when they believe that they are not earning their authorized rates of return on invested capital. The five-year outlook used in my DCF model conforms better to this reality given the fact that it is reasonable to assume that a regulated utility will probably file for new rates within a three to five-year time frame.

Q. Have the comments made by Mr. Grant on page 6 of his rebuttal testimony caused you to change the views that you expressed in your direct testimony?

A. No. As I stated in my direct testimony, the Commission has consistently rejected issues such as company size, customer growth, and the historic test year concept as reasons for making upward adjustments to estimated costs of common equity.

The issue of high customer growth in UNS' service territory certainly never deterred the Company's parent, UniSource Energy Corporation ("UniSource"), from acquiring the natural gas and electric assets from Citizens Communications Company ("Citizens") in the first place. One cannot believe that the management of UniSource, which is based in Tucson, was blind to the fact that they were acquiring assets located in one of the fastest growing states in the U.S. High growth in Arizona is one of UniSource's biggest selling points to potential investors. UniSource even presents high growth in a positive light in the Chairman's Letter to Shareholders that appears in UniSource's 2005 Annual Report (Attachment C). More recently, this same attitude toward growth was reflected in a Company press release dated August 6, 2007 that announced UniSource's second quarter earnings. Nowhere in the press release is customer growth referred to as a negative factor in the Company"s ability to turn a profit. Obviously the investment community does not view UniSource's high growth service territories in a negative light given the fact that shares of UniSource have increased from $25.25, at the time RUCO successfully opposed an acquisition attempt by a limited liability partnership (which included the well heeled Wall Street investment firm of Kolberg Kravis Roberts & Co.), to a current price of $30.05 as of August 21, 2007.

In regard to regulatory lag, unless the utility is operating under an agreement that provides for a rate freeze as I noted earlier, it is the utility that decides when to apply for rate relief and generally utilities apply for rate relief at times when it is an advantage to them. Once again, UniSource's management was well aware of the regulatory environment that they would be operating in when they acquired the electric and natural gas assets from Citizens in 2003. For the reasons stated above I believe that Mr. Grant's arguments regarding additional risk resulting from high customer growth and regulatory lag should be given no weight in this proceeding.

Q. Please respond to Mr. Grant's position that your recommended rate of return falls short of the standards set by the Hope and Bluefield decisions.

A. RUCO believes that the rates it is recommending in this case will provide the Company with the opportunity to recover its operating expenses and provide a return on its invested capital. From that standpoint I believe that the capital attraction standards set forth in the Hope and Bluefield decisions have been satisfied. Ultimately it is up to the Company to manage its expenses and make prudent investments in order to achieve its authorized rate of return. This also means coming in for rate relief on a timely basis. Mr. Grant claims that the Company's projections indicate that UNS will not be able to achieve its authorized rate of return if RUCO's cost of capital recommendation is adopted by the ACC. These are projections made by UNS that are mere speculation. As I pointed out in my direct testimony, Arizona, like the rest of the country, is experiencing a slowdown in the housing market which may well give the Company a chance to take a breather from having to keep up with growth. In regard to the Company's Mohave County operations, unresolved water supply issues and fairly recent events, such as the housing slowdown just noted and a construction setback in the planned Hoover Dam bypass bridge[4], which will provide a faster and more direct route to Las Vegas from Mohave County, will provide the Company with additional time to deal with projected growth related to planned Las Vegas bedroom communities in that portion of UNS' service territory. Mr. Grant is critical of RUCO's position on CWIP, yet nowhere in his rebuttal testimony does Mr. Grant address the fact that RUCO supports the Company's request for a purchased power fuel adjustment clause ("PPFAC") which will mitigate fluctuations in operating income as a result of volatile fuel costs that are beyond the Company's control for the most part.

...

[4] Based on information obtained from a U.S. Department of Transportation newsletter for June 2007(http://www.hooverdambypass.org/Informational_Material.htm), the collapse of a crane has caused a delay of several years on the Hoover Dam Bypass Project. The completion of the bridge and bypass route that will link Mohave County, Arizona and Clark County, Nevada is now estimated to occur sometime toward the end of 2010.

Q. Does your silence on any of the issues or positions addressed in the rebuttal testimony of the Company's witnesses constitute acceptance?

A. No, it does not.

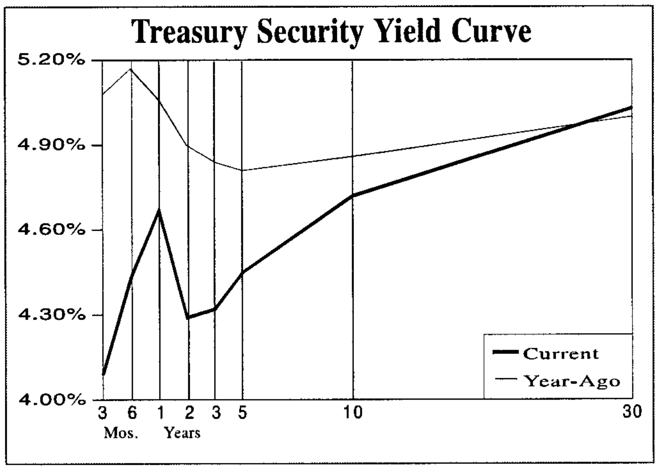
Q. Does this conclude your surrebuttal testimony on UNS?

A. Yes, it does.

ATTACHMENT A

Selected Yields

	Recent (8/15/07)	3 Months Ago (5/16/07)	Year Ago (8/17/06)
TAXABLE			
Market Rates			
Discount Rate	6.25	6.25	6.25
Federal Funds	5.25	5.25	5.25
Prime Rate	8.25	8.25	8.25
30-day CP (A1/P1)	5.26	5.24	5.23
3-month LIBOR	5.52	5.36	5.39
Bank CDs			
6-month	2.99	3.11	3.25
1-year	3.70	3.73	4.02
5-year	4.02	3.91	4.16
U.S. Treasury Securities			
3-month	4.09	4.73	5.08
6-month	4.43	4.84	5.17
1-year	4.67	4.85	5.06
5-year	4.45	4.62	4.81
10-year	4.72	4.71	4.86
10-year (inflation-protected)	2.52	2.37	2.28
30-year	5.03	4.88	5.00
30-year Zero	4.99	4.85	4.91



	Recent (8/15/07)	3 Months Ago (5/16/07)	Year Ago (8/17/06)
Mortgage-Backed Securities			
GNMA 6.5%	6.02	5.58	5.86
FHLMC 6.5% (Gold)	6.17	5.80	6.01
FNMA 6.5%	6.16	5.73	6.12
FNMA ARM	5.48	5.49	5.35
Corporate Bonds			
Financial (10-year) A	6.00	5.69	5.82
Industrial (25/30-year) A	6.19	5.89	6.04
Utility (25/30-year) A	6.28	6.07	6.07
Utility (25/30-year) Baa/BBB	6.41	6.21	6.46
Foreign Bonds (10-Year)			
Canada	4.44	4.24	4.27
Germany	4.34	4.30	3.92
Japan	1.65	1.67	1.83
United Kingdom	5.13	5.13	4.66
Preferred Stocks			
Utility A	7.34	7.29	7.19
Financial A	6.40	6.30	6.19
Financial Adjustable A	5.51	5.52	N/A
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.59	4.24	4.39
25-Bond Index (Revs)	4.67	4.44	4.97
General Obligation Bonds (GOs)			
1-year Aaa	3.62	3.60	3.50
1-year A	6.72	3.70	3.60
5-year Aaa	3.76	3.63	3.58
5-year A	3.86	3.74	3.87
10-year Aaa	4.10	3.76	3.91
10-year A	4.60	4.26	4.32
25/30-year Aaa	4.59	4.13	4.33
25/30-year A	4.84	4.43	4.66
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.88	4.55	4.45
Electric AA	4.84	4.45	4.42
Housing AA	4.95	4.63	4.65
Hospital AA	4.98	4.65	4.70
Toll Road Aaa	4.88	4.55	4.52

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/1/07	**7/18/07**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1573	1667	-94	1599	1561	1588
Borrowed Reserves	245	299	-54	179	132	199
Net Free/Borrowed Reserves	1328	1368	-40	1420	1429	1389

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	7/30/07	**7/23/07**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1371.8	1360.1	11.7	-4.0%	0.3%	-0.1%
M2 (M1+savings+small time deposits)	7283.2	7272.6	10.6	4.8%	5.8%	6.4%

ATTACHMENT B

Cost-of-Service Rates Manual

Federal Energy Regulatory Commission
888 North Capitol Street, N.E.
Washington, D.C. 20426
United States of America
www.ferc.gov

June 1999

Table of Contents

$159,602,000, is equity financed. This means that the owners of Pipeline U.S.A. used their own funds to finance this portion of their investment.

** Pipeline U.S.A. issues its own debt which is not guaranteed by its parent, has its own bond rating and its capital structure is comparable to other equity capitalizations approved by the Commission. Therefore, Pipeline U.S.A. meets the Commission's criteria for using its own capital structure for setting its rates.*

Cost of Debt: This refers to the cost of long term debt incurred by the pipeline to construct or expand the pipeline. For ongoing pipelines that have been issuing debt, we use the actual imbedded cost of debt in the capital structure. The actual imbedded cost of debt is the weighted average of all the debt issued and the cost at which the debt was issued. For new pipelines that have indicated that they would issue debt to finance their investment, but have not yet actually issued the debt, we compute the cost of debt based on a projection, or recent historical debt cost such as historical average Baa utility bonds (Moody's Bond Survey), which is the most prevalent rating for utilities. We also use Moody's to compute the cost of debt if we decide use of a hypothetical capital structure is appropriate.

A-8, column 3, shows the cost of debt of Pipeline U.S.A. of 8.25%. The cost of debt represents a return to Pipeline U.S.A.'s bondholders. The debt return dollars appearing in Column 5 represents the cost to Pipeline U.S.A. to pay the interest on the debt to its bondholders. This debt return, or interest on debt, of $30,723,000 as shown in column (5) is included in the Return component of the cost-of-service.

Return on Equity or Cost of Equity: This is the pipeline's actual profit, or return on its investment. The return on equity is derived from a range of equity returns developed using a Discounted Cash Flow

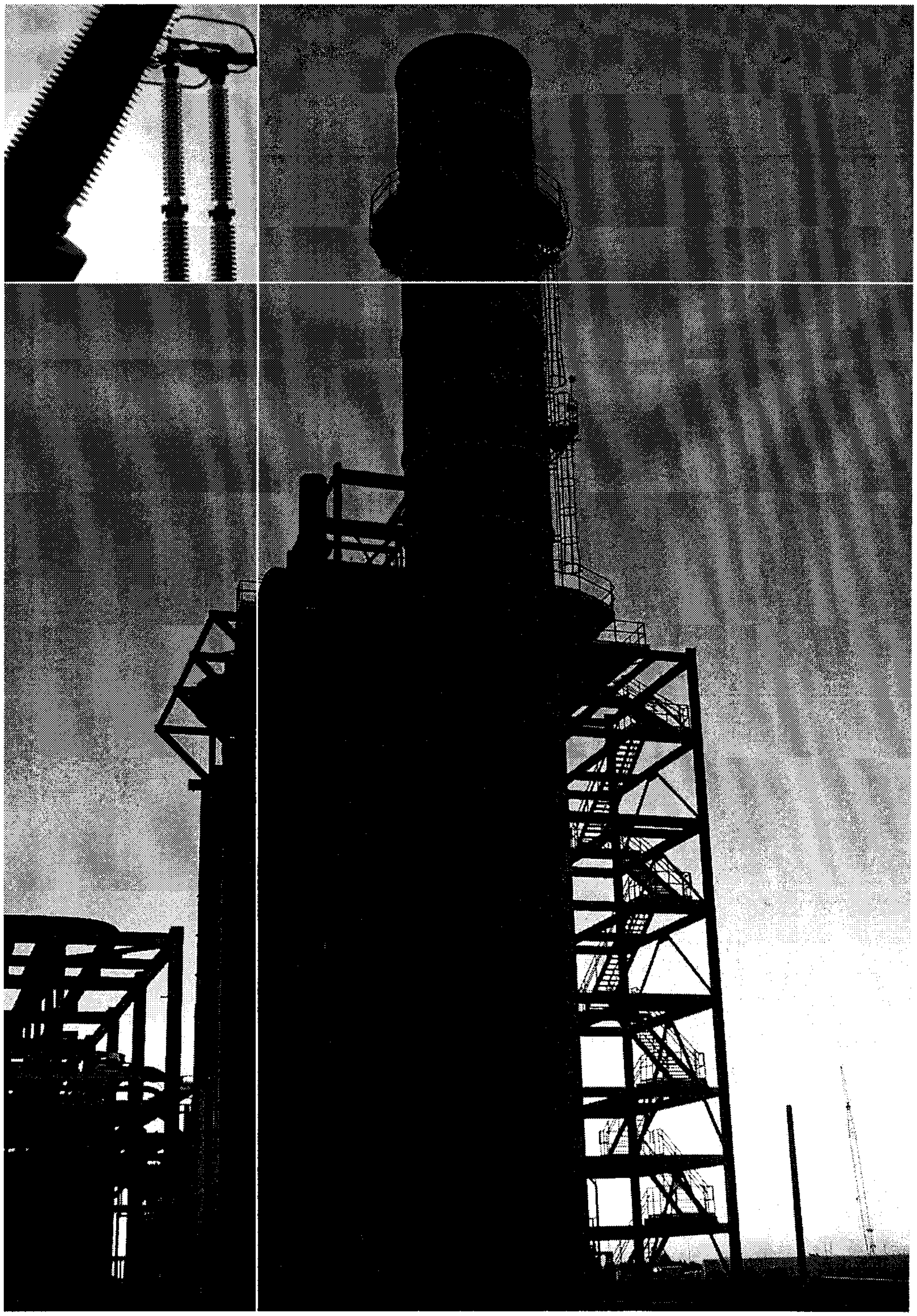
(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term growth estimates and the other long term growth estimates. These estimates are then weighted, two-thirds for the short-term growth projection and one-third on the long-term growth, and utilized in determining a range of reasonable equity returns. Two-thirds is used for the short-term growth rate on the theory that short-term growth rates are more predictable, and thus deserve a higher weighting than long term growth rate projections. An equity return is then selected within this zone based on an analysis of the company's risk. It is assumed, that most pipelines face risks that would place them in the middle of the zone of reasonableness. However, a case could be made depending on the facts of the specific pipeline that the return on equity should be outside the zone. As an example, a pipeline with a high debt capitalization ratio is usually considered more risky and thus, a higher return on equity would be expected.

We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

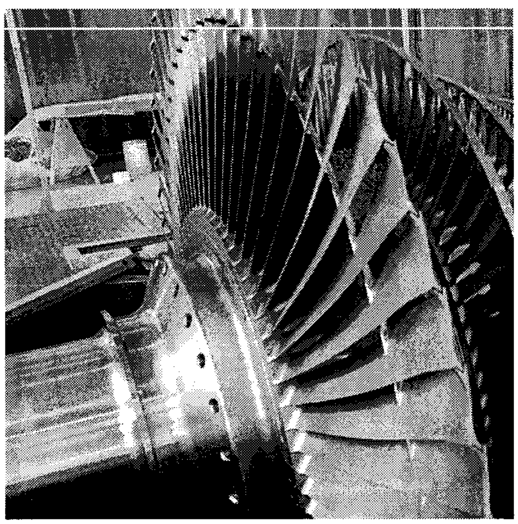
Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues of capitalization ratios and ROE calculations and analyses. Use of a pretax return reduces these issues down to one number, a pretax percentage that can easily be compared to other pipeline's pretax returns. The pretax return figure

ATTACHMENT C

UniSource Energy Corporation
Annual Report 2005



Generating Success



Generating

Confidence

Dear Fellow Shareholder,

In many ways, UniSource Energy Corporation is focused on a single, powerful concept: generation.

Utilities use that term to describe power production – the transformation of coal, natural gas, sunlight and other resources into the electricity that powers our modern lives. But generation means much more than power to UniSource Energy.

Our growing utility business generates positive returns for shareholders as it provides safe, reliable energy for customers. Our infusion of capital into Tucson Electric Power (TEP) and UniSource Energy Services (UES) in 2005 generated confidence in our financial standing, including a two-notch upgrade of TEP's credit rating from Moody's Investors Service. Our proposal to extend TEP's current rate agreement through 2010 would generate a level of price stability virtually unprecedented in today's volatile energy market. And our award-winning employee volunteer program continues to generate goodwill in the communities we serve.

In 2006, our commitment to generation will be apparent in its most literal sense. By year's end, we will have added two new plants to TEP's energy generating operations. The new units will complement the expanding operations of TEP and UES, which now combine to serve approximately 613,000 customers across Arizona.

These new facilities have been years in the making, and their completion will mark a historic expansion of our company's generating operations. But as our progress in other areas makes clear, UniSource Energy isn't just producing power – we're generating success.

Construction of a third unit at TEP's coal-fired Springerville Generating Station (SGS) remains on track with an accelerated timeline that calls for the 400-megawatt (MW) unit to be brought online during the third quarter of 2006. Crews working under the direction of project contractor Bechtel have made steady progress without sacrificing quality or safety. Through the end of 2005, workers had logged more than three million hours on the project without a single lost-time accident.

TEP will operate Unit 3. It also will purchase up to 100 MW of the unit's capacity for up to five years from Tri-State Generation and Transmission Association, a wholesale power cooperative that will lease the completed unit from a financial owner and control its output. In this way, we can capitalize on the expertise we've developed during two decades of power production at SGS while spreading the fixed costs of existing common facilities across an additional unit.

Phoenix-based Salt River Project (SRP), which will purchase 100 MW of Unit 3's output, also holds the right to build a fourth unit at SGS – a 400-MW generator that would be owned by SRP and operated by TEP. SRP has sought more time to evaluate its need for the unit's output.

While Unit 3 is still months away from completion, the expansion of SGS already has delivered significant benefits to TEP. As part of the project, Tri-State funded environmental improvements to Units 1 and 2 to ensure that the total regulated emissions from all four planned units will be significantly lower than previous emissions from the two existing 380-MW units.

Generating Growth

While the effects of those improvements are difficult to detect with the naked eye, they've had a noticeable impact on our bottom line. The reduction in sulfur dioxide (SO_2) output left TEP with a surplus of emissions allowances at a time when the price of this traded commodity was rising. The sale of SO_2 allowances contributed a $13 million pretax gain to TEP's results in 2005, and we're anticipating additional sales in 2006 and beyond.

The new gas-fired Luna Energy Facility, meanwhile, has been built from the ground up with state-of-the-art emissions controls and a combined cycle design that ensures it will serve as a clean, efficient source of power for decades to come.

TEP will share ownership of the facility with Phelps Dodge Energy Services and PNM, an Albuquerque-based utility. PNM will oversee operations of the plant, which is located two miles north of Deming in southern New Mexico. TEP and its partners each hold a one-third stake in the 570-MW facility and will split its output three ways.

Duke Energy had begun construction of the facility in October 2001, but it suspended work about a year later after investing $275 million in the project. TEP, Phelps Dodge and PNM bought the unfinished plant in November 2004 for $40 million. TEP invested about $50 million of internally generated cash toward the purchase and completion of the facility.

The power TEP will receive from both Luna and SGS 3 will expand our wholesale sales opportunities while ensuring our ability to meet the growing needs of our retail customers. Electric usage by TEP customers peaked at 2,225 MW in the summer of 2005, a nearly 7 percent increase over the previous year's peak. Usage should continue to rise along with Tucson's population. TEP's customer base is growing between 2 and 3 percent each year, well ahead of the nation's 1 percent annual population growth rate.

TEP has served this growth without sacrificing reliability or customer service. Our ability to minimize outages and to restore service promptly when interruptions do occur ranked well ahead of recent regional averages in 2005. Meanwhile, TEP once again finished among the leaders in customer satisfaction for western electric utilities last year, according to J.D. Power and Associates' 2005 Electric Utility Residential Customer Satisfaction Study.

Growth also is a defining characteristic of UniSource Energy Services, which serves some of Arizona's fastest growing communities. UES' gas utility, which operates in northern Arizona as well as Santa Cruz County on the U.S.-Mexico border, enjoyed greater than 4 percent customer growth last year. The customer base for the company's electric operations in Santa Cruz and Mohave Counties grew nearly 5 percent in 2005.

To help TEP and UES manage these dramatic growth levels, we completed a financial restructuring in 2005 that bolstered the stability of both utilities. Taking advantage of favorable financial markets, UniSource Energy issued $240 million in debt and used the proceeds, along with internal cash, to retire $320 million of debt obligations at TEP while contributing $20 million to UNS Electric and UNS Gas, the operating subsidiaries of UES. The transactions significantly improved the equity position of TEP while providing additional resources to help UES fund its growing needs.

Generating Stability

While skyrocketing natural gas prices and other cost increases have put upward pressure on utility expenses, retail customers of both TEP and UES enjoy the stability and predictability that come from long-term rate freezes. The base rates for UES service are frozen through at least August 2007, while TEP's rates are capped through the end of 2008.

Rising operational costs and increasing capital investments will compel us to file requests later this year for increased UES gas and electric rates that would take effect after the current rate freeze expires. In the meantime, we've asked the Arizona Corporation Commission (ACC) to update the formula used to calculate how wholesale gas costs are passed along to UNS Gas customers. At times, the current formula hasn't kept up with dramatic price increases, delaying recovery of our gas purchase costs.

For TEP, though, we're looking to extend the period of rate stability for customers for another two years. We've asked the ACC to maintain TEP's current rates through 2010 with the addition of an energy cost provision that would take effect in 2009. This new mechanism would help account for changes in market power costs since the settlement agreement establishing TEP's current rates was signed in 1999. This proposed extension was designed to provide TEP with some protection from market volatility while sparing customers from dramatic cost increases that could result from the initiation of market pricing contemplated under that settlement agreement.

The extended cap on TEP's rates has not prevented our Board of Directors from rewarding shareholders with rising dividend payments. Earlier this year, the Board voted to increase the quarterly payments to $0.21 per share, the sixth annual increase since the dividend was established at $.08 per share in 2000.

The Board's vote of confidence is particularly meaningful in light of our disappointing financial performance in 2005. UniSource Energy's year-end earnings of $46.1 million, or $1.33 per basic share of common stock, reflect the heavy toll of an extended shutdown of SGS Unit 2 and other plant outages. The unplanned outage struck SGS Unit 2 in August, when customer demand was high and energy prices were boosted by the impact of Gulf Coast hurricane activity. The outage contributed to an 82 percent increase in TEP's purchased power expense in 2005, offsetting our utility revenue growth and the benefits of our financial restructuring.

As a result, we did not achieve my 2005 earnings goal of $1.50 to $1.75 per share. And while the $276 million in operating cash produced by UniSource Energy was strong by most measures, it fell short of my $300 million goal for the year. Despite this shortfall, we internally funded our entire capital expenditure requirements of $203 million, including the Luna Energy Facility project.

I was further disappointed by increased losses at Millennium Energy Holdings, which contains UniSource Energy's unregulated investments. The increase was almost entirely due to higher costs at Global Solar Energy, a company that develops thin-film photovoltaic material. We have agreed to sell Global Solar in a transaction that would allow us to repurchase between 5 and 10 percent of the company for a nominal fee, giving us an opportunity to capitalize on its future success. The sale is consistent with our strategy of scaling back Millennium's involvement in actively managed investments to focus on UniSource Energy's core utility operations.

Generating

Goodwill

That focus will continue to include a strong emphasis on community service. Employees at both TEP and UES joined their friends and families in contributing nearly 39,000 hours of their own time to charitable activities in 2005. We've also asked our employees to provide direction for UniSource Energy's corporate giving program, rewarding their efforts with critical support for the causes most important to them. This strategy, which continues to attract significant national acclaim, has served to strengthen the bonds between our employees and the communities we serve together.

Our bond with some of TEP's most critical employees was solidified earlier this year when the International Brotherhood of Electrical Workers Local 1116 ratified a comprehensive three-year labor agreement. The agreement, which will remain in effect through January 2009, provides a balanced wage and benefit package that serves the long-term interests of both the company and our employees.

With a committed work force, a solid financial base and expanding utility operations, UniSource Energy is in a strong position to produce improving results in 2006 and beyond. In addition to the completion of SGS 3 and the Luna Energy Facility, my goals for this year include improved availability from our existing generating units, particularly during the critical summer months. We'll also press for resolution of the disagreement over the basis of TEP's future rates while addressing the need to increase the rates charged by UNS Gas and UNS Electric.

Other goals include the successful implementation of a new billing system that will improve customer service and streamline the operations of TEP, UNS Gas and UNS Electric. The upgrade, which replaces three separate older systems, is a highlight of our ongoing campaign to improve our business processes – an effort that will receive even greater emphasis this year. The success of these measures and the continued growth of our utility businesses should help us achieve year-end earnings between $1.65 and $2.05 per share for 2006.

I would like to thank you, my fellow shareholders, for your continued faith in UniSource Energy. I would also like to thank our employees, who have pursued our goals with admirable resolve. Together, we've invested in our future and followed a course that leaves us poised to capitalize on growth instead of falling victim to it. Such strategic planning is key for regulated utilities because we operate in a unique environment; unlike other companies, we provide a product far more valuable than the price our customers pay. In so doing, we create significant benefits for customers at the same time we're producing value for our shareholders. In 2006 and beyond, UniSource Energy will remain committed to generating success on both these fronts.

Your fellow shareholder,

James S. Pignatelli
Chairman, President and CEO
UniSource Energy Corporation

ATTACHMENT D

News Releases

UniSource Energy Reports Second Quarter Earnings for 2007

TUCSON, Ariz., Aug 06, 2007 (BUSINESS WIRE) --

UniSource Energy Corp. (NYSE: UNS) today reported earnings for the second quarter of 2007 of $12 million, or $0.32 per diluted share of common stock. Last year, UniSource Energy reported second quarter earnings of $10 million, or $0.28 per diluted share. UniSource Energy modified its 2007 full-year earnings guidance to be between $1.55 and $1.85 per diluted share from its previous range of between $1.55 and $1.95 per diluted share.

The customer base at Tucson Electric Power (TEP), UniSource Energy's principal subsidiary, continued to grow at an annual rate of 2 percent. Customer growth was offset by a 14 percent decrease in the number of cooling degree days that led to reduced residential energy usage and only a modest increase in retail revenues compared with the same period last year.

Higher fuel and purchased power expenses were largely offset by increased wholesale revenues made possible by the improved availability of TEP's generating fleet. Revenues from the operation of a new coal-fired unit at TEP's Springerville Generating Station (SGS) and higher sales of sulfur dioxide (SO_2) emissions credits mitigated increases in other expenses.

UniSource Energy's second quarter results reflect TEP's rising power production costs, including a $9 million year-over-year increase in coal-related fuel expense. A 9 percent increase in kilowatt-hours generated from TEP's coal-fired plants and rising coal and rail costs led to the increase. The cost per ton of coal delivered to TEP's H. Wilson Sundt Generating Station in Tucson increased nearly 70 percent under a new agreement signed in December 2006. TEP also incurred higher mining costs associated with its interest in the San Juan Generating Station.

"Our reliable generation fleet and efficient operations have helped us manage the rising cost of serving our growing customer base on fixed rates," said James S. Pignatelli, UniSource Energy's Chairman, President and CEO.

TEP added 9,252 new customers during the past year, reaching 394,717 total customers by the end of the second quarter. Despite milder weather, the utility set a new retail peak on July 5 with a net hourly load of 2,370 megawatts (MW) compared with a peak retail load of 2,365 MW in 2006.

TEP filed a request last month for its first rate increase in more than a decade. The company has asked the Arizona Corporation Commission (ACC) to use one of three proposed methods to set new rates that would take effect no later than January 1, 2009. The proposals would increase retail rates by an average of 15 to 23 percent, depending on the approach used.

Second quarter earnings were slightly higher than last year at UniSource Energy Services (UES), which provides gas and electric service in northern and southern Arizona through subsidiaries UNS Electric and UNS Gas. UNS Electric reported earnings of $2 million, a small improvement compared with last year, while UNS Gas matched its $1 million quarterly loss.

Tucson Electric Power Company

TEP reported earnings for the second quarter of 2007 of $12 million compared with $11 million in 2006.

Factors affecting TEP's second quarter 2007 results include:

-- A $13 million increase in retail and wholesale revenues, mostly offset by a $12 million increase in fuel and purchased power costs. Retail revenues increased only $1 million due to milder weather;

-- A $6 million increase in other revenues for fees and reimbursements received from Tri-State Generation and Transmission Association (Tri-State) for fuel and operations and maintenance (O&M) costs related to SGS Unit 3;

-- A $3 million increase in O&M expense due primarily to costs related to TEP's operations of SGS Unit 3 that are reimbursed by Tri-State. O&M expense also includes a pre-tax gain of $5 million related to sales of excess SO2 Emission Allowances, compared with a pre-tax gain of $2 million in the same period last year;

-- A $2 million increase in expenses related to the amortization of the transition recovery asset; and

-- A $2 million decrease in interest expense due to lower capital lease obligation balances.

UNS Gas

UNS Gas reported a net loss of $1 million in the second quarters of 2007 and 2006.

Retail therm sales were flat compared with the second quarter of 2006 as a 3-percent increase in customers was offset by mild weather. Despite similar sales, retail revenues dropped due to a lower commodity surcharge.

UNS Gas filed a general rate case in July 2006 requesting an increase of $9.6 million, or about 7 percent, to cover the growing cost of serving customers. The case is pending before the ACC, and new rates are expected to go into effect in late 2007.

UNS Electric

UNS Electric reported earnings of $2 million for the second quarter of 2007, slightly ahead of last year. UNS Electric's operations are seasonal in nature, with peak energy demand occurring in the summer months. UNS Electric's customer base grew by approximately 3-percent from the same period last year.

In December 2006, UNS Electric filed a general rate case seeking an average rate increase of $8.5 million, or approximately 5.5 percent, to recover rising costs. ACC hearings in the case are scheduled to begin in September 2007, and new rates are expected to go into effect in early 2008.

Year-to-Date

UniSource Energy's consolidated year-to-date earnings through June 30, 2007, were $17 million, or $0.46 per diluted share of common stock. During the same period last year, UniSource Energy reported earnings of $27 million, or $0.73 per diluted share.

Earnings Per Share Summary

Net Income	2nd Quarter 2007	2nd Quarter 2006	Year-to-Date June 30, 2007	Year-to-Date June 30, 2006
	-Millions-		-Millions-	
Tucson Electric Power	$ 12.3	$ 11.2	$ 13.1	$ 27.8
UNS Gas	(1.1)	(1.3)	3.4	3.4
UNS Electric	1.5	1.4	1.9	2.1
Other (1)	(0.9)	(1.3)	(1.7)	(3.8)
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	$ 11.8	$ 10.0	$ 16.7	$ 29.5
Discontinued Operations - Net of Tax (2)	-	-	-	(2.7)
Net Income	$ 11.8	$ 10.0	$ 16.7	$ 26.8
Avg. Basic Shares Outstanding (millions)	35.5	35.2	35.4	35.2

Earnings Per UniSource Energy Share	2nd Quarter 2007	2nd Quarter 2006	Year-to-Date June 30, 2007	Year-to-Date June 30, 2006
Tucson Electric Power	$ 0.35	$ 0.32	$ 0.37	$ 0.79
UNS Gas	(0.03)	(0.04)	0.09	0.10
UNS Electric	0.04	0.04	0.06	0.06
Other (1)	(0.03)	(0.04)	(0.05)	(0.11)
Income Before Discontinued Operations and Cumulative Effect of Accounting Change	$ 0.33	$ 0.28	$ 0.47	$ 0.84
Discontinued Operations - Net of Tax (2)	-	-	-	(0.08)
Net Income per Basic Share	$ 0.33	$ 0.28	$ 0.47	$ 0.76
Net Income per Diluted Share	$ 0.32	$ 0.28	$ 0.46	$ 0.73

(1) Includes UniSource Energy on a stand-alone basis and results from Millennium Energy Holdings, Inc. (Millennium), a wholly-owned subsidiary of UniSource Energy.

(2) Relates to the discontinued operations and sale of Global Solar Energy, Inc. by Millennium on March 31, 2006.

UniSource Energy believes the presentation of TEP, UNS Gas, UNS Electric and Other segment net income or loss on a per basic UniSource Energy share basis, which are non-GAAP financial measures, provides useful information to investors by disclosing the results of operations of its business segments on a basis consistent with UniSource Energy's reported earnings.

Earnings Outlook

UniSource Energy modified its 2007 full-year earnings to be between $1.55 and $1.85 per diluted share.

Numerous factors can affect UniSource Energy's ability to reach the 2007 estimate, including but not limited to: rising fuel and transportation costs; market prices for power in the second half of 2007; unexpected increases in O&M performance of TEP's generating plants; resolution of pending litigation matters; regulatory decisions; the weather; the pace and strength of the regional economy and changes in accounting standards.

UniSource Energy's earnings are subject to the seasonal energy sales of its utilities. Generally, TEP records a significant portion of its earnings during the third quarter as a result of peak energy usage during the summer.

Conference Call and Webcast

UniSource Energy officials will discuss second quarter 2007 earnings and outlook for 2007 on Tuesday, August 7, 2007 beginning at 12 p.m. EDT in a conference call that will be available live on the Internet. James S. Pignatelli, UniSource Energy Chairman, President and CEO, will host the call.

Internet Access

A live audio-only webcast of the conference call is available through a link at uns.com. Listeners are encouraged to visit the Web site at least 30 minutes before the event to register, download and install any necessary audio software. A recording of the webcast will be available for 30 days through a link at uns.com.

Telephone Access

To listen to the live conference call, dial 877-582-0446 five to 10 minutes prior to the event and reference confirmation code 10745561. A telephone replay will be available for seven days starting August 7. To listen to the replay, dial 800-642-1687 and reference confirmation code 10745561.

UniSource Energy's primary subsidiaries include Tucson Electric Power, which serves more than 394,000 customers in southern Arizona; UniSource Energy Services, provider of natural gas and electric service for approximately 240,000 customers in northern and southern Arizona; and Millennium Energy Holdings, parent company of UniSource Energy's unregulated energy businesses. For more information about UniSource Energy and its subsidiaries, visit uns.com.

This news release contains forward-looking information that involves risks and uncertainties that include, but are not limited to: changes in accounting standards; the outcome of regulatory proceedings; the ongoing restructuring of the electric industry; regional economic and market conditions which could affect customer growth and the cost of fuel and power supplies; changes to long-term contracts; performance of TEP's generating plants; the weather; changes in asset depreciable lives; changes related to the recognition of unbilled revenue; the cost of debt and equity capital; and other factors listed in UniSource Energy's Form 10-K and 10-Q filings with the Securities and Exchange Commission. The preceding factors may cause future results to differ materially from outcomes currently expected by UniSource Energy.

UNISOURCE ENERGY 2007 RESULTS

UniSource Energy Corporation
Condensed Consolidated Statements of Income

(in thousands of dollars, except per share amounts)	Three Months Ended June 30,		Increase / (Decrease)	
(UNAUDITED)	2007	2006	Amount	Percent
Operating Revenues				
Electric Retail Sales	$ 249,462	$ 247,387	$ 2,075	0.8
Electric Wholesale Sales	44,525	31,867	12,658	39.7
Gas Revenue	22,850	25,720	(2,870)	(11.2)
Other Revenues	12,935	10,417	2,518	24.2
Total Operating Revenues	329,772	315,391	14,381	4.6
Operating Expenses				
Fuel	72,208	69,143	3,065	4.4
Purchased Energy	81,229	74,403	6,826	9.2
Other Operations and Maintenance	63,304	61,735	1,569	2.5
Depreciation and Amortization	34,515	32,680	1,835	5.6
Amortization of Transition Recovery Asset	19,219	17,279	1,940	11.2
Taxes Other Than Income Taxes	12,166	12,360	(194)	(1.6)
Total Operating Expenses	282,641	267,600	15,041	5.6
Operating Income	47,131	47,791	(660)	(1.4)
Other Income (Deductions)				
Interest Income	4,456	5,142	(686)	(13.3)
Other Income	4,328	1,987	2,341	N/M
Other Expense	(1,614)	(246)	(1,368)	N/M
Total Other Income (Deductions)	7,170	6,883	287	4.2
Interest Expense				
Long-Term Debt	18,276	19,208	(932)	(4.9)
Interest on Capital Leases	16,126	18,526	(2,400)	(13.0)
Other Interest Expense	1,651	1,267	384	30.3
Interest Capitalized	(1,634)	(1,436)	(198)	(13.8)
Total Interest Expense	34,419	37,565	(3,146)	(8.4)
Income Before Income Taxes	19,882	17,109	2,773	16.2
Income Tax Expense	8,076	7,111	965	13.6
Net Income	$ 11,806	$ 9,998	$ 1,808	18.1

Weighted-average Shares of Common Stock Outstanding (000)	35,472	35,245	227	0.6
Basic Earnings per Share	$ 0.33	$ 0.28	$ 0.05	17.9
Diluted Earnings per Share	$ 0.32	$ 0.28	$ 0.04	14.3
Dividends Declared per Share	$ 0.225	$ 0.21	$ 0.015	7.1

Tucson Electric Power	Three Months Ended June 30,		Increase / (Decrease)	
Electric MWh Sales:	2007	2006	Amount	Percent
Retail Sales	2,447,563	2,428,745	18,818	0.8
Wholesale Sales	825,324	647,589	177,735	27.4
Total	3,272,887	3,076,334	196,553	6.4

N/M - Not Meaningful

Reclassifications have been made to prior periods to conform to the current period's presentation.

UNISOURCE ENERGY 2007 RESULTS

UniSource Energy Corporation

Condensed Consolidated Statements of Income

(in thousands of dollars, except per share amounts)	Six Months Ended June 30,		Increase / (Decrease)	
(UNAUDITED)	2007	2006	Amount	Percent
Operating Revenues				
Electric Retail Sales	$ 445,212	$ 430,056	$ 15,156	3.5
Electric Wholesale Sales	93,290	88,554	4,736	5.3
Gas Revenue	84,960	88,535	(3,575)	(4.0)
Other Revenues	24,151	13,672	10,479	76.6
Total Operating Revenues	647,613	620,817	26,796	4.3

Operating Expenses

Fuel	133,288	119,359	13,929	11.7
Purchased Energy	167,036	156,558	10,478	6.7
Other Operations and Maintenance	134,120	115,550	18,570	16.1
Depreciation and Amortization	68,981	63,437	5,544	8.7
Amortization of Transition Recovery Asset	34,205	29,121	5,084	17.5
Taxes Other Than Income Taxes	24,653	24,913	(260)	(1.0)
Total Operating Expenses	562,283	508,938	53,345	10.5
Operating Income	85,330	111,879	(26,549)	(23.7)
Other Income (Deductions)				
Interest Income	8,900	10,069	(1,169)	(11.6)
Other Income	5,643	3,622	2,021	55.8
Other Expense	(2,251)	(974)	(1,277)	N/M
Total Other Income (Deductions)	12,292	12,717	(425)	(3.3)
Interest Expense				
Long-Term Debt	36,265	37,892	(1,627)	(4.3)
Interest on Capital Leases	32,278	37,073	(4,795)	(12.9)
Other Interest Expense	3,412	2,573	839	32.6
Interest Capitalized	(3,029)	(3,348)	319	9.5
Total Interest Expense	68,926	74,190	(5,264)	(7.1)
Income From Continuing Operations Before Income Taxes	28,696	50,406	(21,710)	(43.1)
Income Tax Expense	11,947	20,917	(8,970)	(42.9)
Income From Continuing Operations	16,749	29,489	(12,740)	(43.2)
Discontinued Operations - Net of Tax	-	(2,669)	2,669	N/M
Net Income	$ 16,749	$ 26,820	$(10,071)	(37.6)
Weighted-average Shares of Common Stock Outstanding (000)	35,447	35,181	266	0.8
Basic Earnings (Loss) per Share				

Income from Continuing Operations	$ 0.47	$ 0.84	$ (0.37)	(44.0)
Discontinued Operations - Net of Tax	-	$ (0.08)	$ 0.08	N/M
Net Income	$ 0.47	$ 0.76	$ (0.29)	(38.2)
Diluted Earnings (Loss) per Share				
Income from Continuing Operations	$ 0.46	$ 0.80	$ (0.34)	(42.5)
Discontinued Operations - Net of Tax	-	$ (0.07)	$ 0.07	N/M
Net Income	$ 0.46	$ 0.73	$ (0.27)	(37.0)
Dividends Declared per Share	$ 0.45	$ 0.42	$ 0.03	7.1

Tucson Electric Power	Six Months Ended June 30,		Increase / (Decrease)	
Electric MWh Sales:	2007	2006	Amount	Percent
Retail Sales	4,459,834	4,302,561	157,273	3.7
Wholesale Sales	1,659,962	1,659,579	383	0.0
Total	6,119,796	5,962,140	157,656	2.6

N/M - Not Meaningful

Reclassifications have been made to prior periods to conform to the current period's presentation.

SOURCE: UniSource Energy Corp.

UniSource Energy Corp., Tucson
Art McDonald, 520-884-3628 (Media)
Jo Smith, 520-884-3650 (Financial Analyst)

Current Stock Price
UNS 29.98 + 0.01
Aug 21 12:10 PM ET
delayed 20 minutes

EXHIBIT
tabbies
RUCO 15
Admitted

UNS Electric, Inc.
Docket No. E-04204A-06-0783
Rate Application

SUMMARY OF THE TESTIMONY OF WILLIAM A. RIGSBY, CRRA ON BEHALF OF THE RESIDENTIAL UTILITY CONSUMER OFFICE

The following is a summary of the significant issues set forth in both the Direct and the Surrebuttal Testimony of RUCO witness William A. Rigsby, on UNS Electric, Inc.'s ("UNS" or the "Company") application for a permanent rate increase. A full discussion of the cost of capital issues associated with UNS' request for rate relief and the underlying theory and rationales for Mr. Rigsby's recommendations are contained in the referenced documents. The significant issues associated with the case are as follows:

COST OF CAPITAL:

<u>Capital Structure</u> – Mr. Rigsby is recommending that the Commission adopt the Company-proposed capital structure which is comprised of 3.97 percent short-term debt, 47.18 percent long-term debt and 48.85 percent common equity.

<u>Weighted Cost of Capital</u> – Mr. Rigsby is recommending an 8.67 percent weighted cost of capital. Mr. Rigsby's recommended weighted cost of capital is based on his recommended weighted cost of debt and weighted cost of equity that is contained in his recommended capital structure for UNS.

Cost of Debt – Mr. Rigsby is recommending that the Commission adopt the Company-proposed cost of long-term debt of 8.22 and the Company-proposed cost of short-term debt of 6.36 percent.

Cost of Common Equity – Mr. Rigsby is recommending that the Commission adopt a 9.30 percent cost of common equity. Mr. Rigsby's 9.30 percent figure is based on the results of his cost of equity analysis, which used both the discounted cash flow ("DCF") and capital asset pricing model ("CAPM") methodologies.

EXHIBIT
M-1
Admitted

UniSource Energy Services Electric Rate Proposal At-A-Glance

Basic Information

- The proposed rates would result in a 4.4-percent increase for average residential customers in Mohave County while producing an average 0.6 percent *decrease* for their peers in Santa Cruz County. Residents and smaller business customers in Santa Cruz County have historically paid more than their peers in Mohave County, and UES is proposing a unified rate structure. Changes for other customers vary (see table).
- If the Arizona Corporation Commission (ACC) follows a typical 13-month calendar for such matters, the changes could take effect in spring of 2008.
- The proposed rates would cover the cost of a new 90MW generating facility in Mohave County to help meet peak loads in the fast-growing region. They also include a revised Purchased Power and Fuel Adjustment Charge (PPFAC) to recover energy costs after the current supply contract with Pinnacle West expires in June 2008.
- The rates would allow UES to expand its Energy Smart Homes program, provide new resources for low-income weatherization and fund other energy efficiency programs.
- The proposal would result in the first rate adjustment since August 2003, and the first general rate increase since January 1997.

Increase (or Decrease) in Average Bills in Mohave, Santa Cruz territories*

Customer Class	Mohave	Santa Cruz	Avg kWh/month
Residential	4.4%	(0.6%)	863 **
Small General Service	18.5%	(17.2%)	1,012
Large General Service	5.7%	5.7%	20,215
Large General Service TOU	5.5%	5.5%	24,198
Interruptible Power Service	4.0%	4.0%	74,889

* The impact of changes to Large Power Service rates, which apply to just 11 customers, are highly dependent on individual customer characteristics, so an average is not useful. If the proposed changes had been in place during the test year used in this rate case, UNS Electric would have received a 5.9 percent increase in revenue from those customers.

** Average residential usage is 898 kWh/mo. in Mohave and 718 kWh/mo. in Santa Cruz.

Reasons Behind the Rates

- The new rates will help UES cover the costs of serving customers' growing needs. The company's customer base is expanding by about 5 percent a year, compared to the 2.5 percent annual growth rate of its sister company, Tucson Electric Power.
- UNS Electric's customer count has increased 61 percent (from 57,000 to 92,000) since March 1995, the end of the test year used in Citizens' last general rate case.
- Since UES took over for Citizens in August 2003, the company has invested more than $74 million in infrastructure improvements to serve rising customer demand. Operating costs, meanwhile, have more than doubled since the last general rate case. These costs are not reflected in the company's current rates.
- When UES power supply contract expires in June 2008, the company will have to buy energy for customers at higher market prices. UES already has begun securing contracts and has proposed acquiring two planned 45-MW gas turbines in Mohave County.

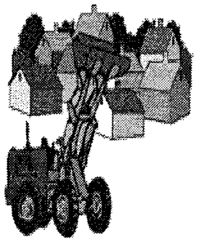
New Rate Design

- For residential customers, the new rates include a higher monthly customer charge – $8 per month, up from $6.50 – to cover increased infrastructure costs. A staggered energy charge would set a lower price for the first 400 kWh used, encouraging conservation.
- New time-of-use rates, available to all and automatic for new customers, would allow lower average rates for those who shift usage away from peak periods.
- A flat $8/month CARES discount for low-income customers would replace the existing usage-based discount, encourage conservation.
- New Warm Spirit program will raise contributions for a fund to help local agencies provide emergency bill payment assistance to low-income customers. UES will provide up to $25,000 per year to match customer contributions to the program.

EXHIBIT
M-2
Almuttaol

U.S. Census Bureau

2006 Building Permits



Monthly New Privately-Owned Residential Building Permits Mohave County Unincorporated Area, Arizona (Mohave County - 015)

Annual 2006 Go!

Item	Annual 2006 Buildings	Units	Construction cost
Browse Single Family	784	784	143,966,451
Browse Two Family	2	4	470,369
Browse Three and Four Family	0	0	0
Browse Five or More Family	0	0	0
Browse Total	786	788	144,436,820

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
Building Permit Estimates - U.S., State, and Metropolitan Areas Click this

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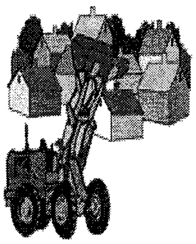
M -

U.S. Census Bureau

2006 Building Permits



Monthly New Privately-Owned Residential Building Permits Lake Havasu City, Arizona (Mohave County - 015)

Annual 2006 Go!

Item	Annual 2006 Buildings	Units	Construction cost
Browse Single Family	536	536	102,646,325
Browse Two Family	34	68	6,389,609
Browse Three and Four Family	13	39	4,215,230
Browse Five or More Family	1	6	605,552
Browse Total	584	649	113,856,716

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
Building Permit Estimates - U.S., State, and Metropolitan Areas Click this

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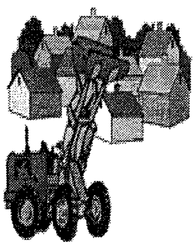
M –

U.S. Census Bureau

2006 Building Permits



Monthly New Privately-Owned Residential Building Permits Kingman, Arizona (Mohave County - 015)

Annual 2006 Go!

Item	Annual 2006		
	Buildings	Units	Construction cost
Browse Single Family	309	309	51,720,590
Browse Two Family	8	16	1,866,999
Browse Three and Four Family	4	12	1,022,771
Browse Five or More Family	1	57	1,581,970
Browse Total	322	394	56,192,330

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
Building Permit Estimates - U.S., State, and Metropolitan Areas Click this

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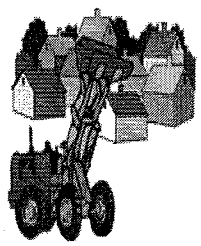
U.S. Census Bureau

2006 Building Permits



Monthly New Privately-Owned Residential Building Permits Bullhead City, Arizona (Mohave County - 015)

Annual 2006 Go!

Item	Annual 2006 Buildings	Units	Construction cost
Browse Single Family	597	597	69,041,392
Browse Two Family	2	4	292,639
Browse Three and Four Family	35	139	10,063,316
Browse Five or More Family	7	82	6,058,722
Browse Total	641	822	85,456,069

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
Building Permit Estimates - U.S., State, and Metropolitan Areas Click this

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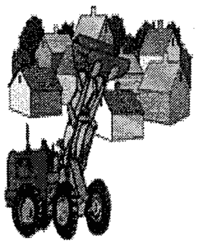
U.S. Census Bureau

2006 Building Permits



Monthly New Privately-Owned Residential Building Permits
Nogales, Arizona (Santa Cruz County - 023)

Annual 2006 Go!

Item	Annual 2006		
	Buildings	Units	Construction cost
Browse Single Family	26	26	5,263,710
Browse Two Family	0	0	0
Browse Three and Four Family	0	0	0
Browse Five or More Family	0	0	0
Browse Total	26	26	5,263,710

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
Building Permit Estimates - U.S., State, and Metropolitan Areas Click this

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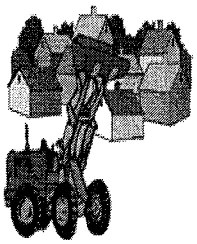
U.S. Census Bureau

2006 Building Permits



Monthly New Privately-Owned Residential Building Permits Santa Cruz County Unincorporated Area, Arizona (Santa Cruz County - 023)

Annual 2006 Go!

Item	Annual 2006		
	Buildings	Units	Construction cost
Browse Single Family	663	663	113,407,002
Browse Two Family	1	2	188,028
Browse Three and Four Family	1	3	282,846
Browse Five or More Family	8	61	5,816,754
Browse Total	673	729	119,694,630

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
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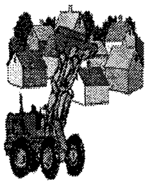
U.S. Census Bureau

2007 Building Permits



Monthly New Privately-Owned Residential Building Permits
Santa Cruz County Unincorporated Area, Arizona
(Santa Cruz County - 023)

May 2007 Go!

		May,2007			Cumulative Year to Date					
					Estimates with Imputation			Reported only		
	Item	Buildings	Units	Construction cost	Buildings	Units	Construction cost	Buildings	Units	Construction cost
Browse	Single Family	37	37	7,417,030	179	179	35,622,519	179	179	35,622,519
Browse	Two Family	0	0	0	0	0	0	0	0	0
Browse	Three and Four Family	0	0	0	1	3	162,819	1	3	162,819
Browse	Five or More Family	0	0	0	0	0	0	0	0	0
Browse	Total	37	37	7,417,030	180	182	35,785,338	180	182	35,785,338

[N/A = Reported data not available for the current month]
Source: U.S. Bureau of the Census
Building Permit Estimates - U.S., State, and Metropolitan Areas Click this

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USCENSUSBUREAU
Helping You Make Informed Decisions

EXHIBIT
M-4
~~Admitted~~

RIO RICO TOPS LIST

August building permits in SCC top $10 million

Nogales International

Builders in Santa Cruz County spent $10,670,904 in construction costs in August. Nogales builders spent $1,430,763. Builders in Rio Rico shelled out $8,011,813 while the rest of the county spent $1,228,328. Here they are.

Nogales

1 duplex
1 triplex

Luis Parra, 377 E. Camino Vista Del Cielo, remodel, $45,000; Copper State Bolt & Nut, 1060 N. Mariposa, Rd., new commercial building, $597,015; Beatriz Flores, 945 W. Manor Dr., carport, $1,500; Martin Tamayo, 409 E. Baffert Dr., commercial expansion, $7,000; Pearson's Signs, 30 Calle Sonora E., sign, $800; Exquisito, 165 W. Mariposa Rd., commercial improvement, $2,000; Antonio Montes, 193 E. Morley Ave., commercial expansion, $4,500; Rodrigo Castro, 51 E. Maya Dr., commercial electric, $800; Nazario Ochoa, 190 W. Third St., canopy, $4,500; Los Tacos, 550 Grand Ave. N., expansion, $9,500; Allan Fire Protection, 2420 Frank Reed Rd., sprinkler system, $4,500; 835 N. Grand Ave. LLC, 825 N. Grand Ave., sprinkler system, $40,000; Carla Villalpando, 239 W. Smelter St., electric, $500; Yardena Garma, 514 W. Noon St., electric, $300; Ana Astrid Guevara, 1275 Patagonia Hwy., electric permit; Safeway, 465 W. Mariposa Rd., commercial improvement, $223,940; Jesus and Alejandra Garcia, 330 N. Paseo Del Sur, new triplex, $148,717; Agri Packing Supply, 2420 N. Frank Reed Rd., commercial expansion, $30,617; Raul Martinez, 2420 N. Frank Reed Rd., expansion, $45,000; Manuel De La Riva, 1481 N. Industrial Park, tenant improvement, $8,000; Attitudes H&N LLC, 721 N. Western Ave., commercial improvement, $2,500; Norma Ramirez, 665 N. Goodman St., residential electric, $200; Manuel Riva, 675 E. Maya St., residential storage, $700; Maria De Carmen Gutierrez, 30 Martan Rd., addition, $49,320; Christopher Dominguez, 3 Domico Ct., new duplex, $221,354.

Rio Rico

22 residences
1 duplex

Javier Angulo, 585 Yak Lane, new residence, $112,800; Javier Luis Angulo, 612 Paseo Reforma, new residence, $146,336; Uriel Fernandez, 1126 Hodges Circle, electrical permit; Jesus and Jesus Jr., Cortes, 1185 Circulo Mercado, new restaurant, $468,709; Eduardo and Maria Cervantes, 453 Beso Ct., new residence, $130,942; Rio Rico Properties Inc., 1773 Via Medusa, new residence, $140,068; Jose Valencia, 1185 Olla Ct., new garage and porch, $34,606; Frank and Mercedes Vasquez, 227 Arikara Calle, new porch, $7,200; Manuel Fajardo, 1102 Panda Ct., $16,890; Alan Maytorena, 1096 Sicomoro Ct., new porch, $8,220; Jesus Rodolfo and Margarita Romo, 964 Prodo Lane, new residence, $144,422; Eunice Maria Lopez, 1075 Circulo Golondrina, addition, $101,807; Oscar Robles, 960 Calle Dura, porch addition, $9,825; John and Bertha Kechsner, 646 Camino Kansas, new residence, $197,212; Charles and Dixie Kraesig, 478 Calle Cipres, new residence, $197,212; Most Holy Nativity Catholic Church, 395 Avenida Coatimundi, electric; David Alvarez, 272 Camino Josefina, new balcony, $2,500; Joseph H. Johndrow, 397 Camino Canoa, new fireplace; Marco Flores, 1159 Escorpion Ct., new garage, $18,172; Tapia Builders LLC, 282 Tlaxcala Ct., new residence, $163,096; Cesar Garza Salazar, 1624 Duelo Ct., new residence, $143,570; Montan Developers Inc., 118 Circulo Penjamo, new residence, $145,461; Montan Developers Inc., 1187 Calle Remedios, new residence, $144,425; Rodolfo Perez, 1277 Calle Chaparral, porch addition, $14,730; Ernesto Ramirez, 153 Camino Mariposa, addition, $12,300; Eugenio and Aurelia Romero, 1171 Circulo Golfo, new porch and carport, $19,700; Eduardo Perez, 281 Paseo Mascota, new swimming pool, $18,900; James and Cheryl Todd Derickson, 357 Calle Muelle, new swimming pool, $9,180; Rio Rico Properties Inc., 622 Camino Kansas, new residence, $140,068; Rio Rico Properties Inc., 1835 Alpine Ct., new residence, $157,483; Carms Builders Inc., 170 Calle Pulpo, new residence, $122,253; Cricket Communications, 455 Camino Agosto, six additional cell phone antennas on an existing tower, $35,000; Rio Rico Properties Inc., 1794 Ariosto Ct., new residence, $136,131; Antares Properties, 664 W. Frontage Rd., grading; Rio Rico Properties Inc., 163 Calle Colima, new residence, $136,131; Jolap LLC, 1279 W. Frontage Rd., new warehouse, $1,372,673; Jose L. and Ana Gutierrez Carrillo, 191 Agua Sarca, new residence, $161,399; Rafael Landa, 202 Petalo Ct., new roof, $5,471; Jerry and Jennifer Morningstar, 711 Camino Arruza, new residence, $287,624; Rancisco Romero, 328 Via Pantera, new residence, $191,362; Rodney and Phyllis Halliman, 8 Calle Tubatama, electrical service upgrade; Mas Melons and Grapes, 41 Kipper St., new warehouse, $1,835,738; Carmen Pottinger, 1033 Misa Ct., new residence, $167,200; Irasema Estrada, 431 Sendero Loro, new duplex, $196,612; Rio Rico Properties, 1707 Camino Barrer, new residence, $140,807; Manuel and Amparo Castillo and Diaz, 894 Via Puebla, new residence, $152,010; Jesus M Ayala, 1187 Olla Ct., new retaining wall, $3,000; Ignacio and Alma Ortega, 945 Olivos Ct., addition, $40,000; Miguel Maravilla Jr., 1220 Calle Aquilar, new residence, $117,680; Alejandro M Puig, 1099 Tia Ct., new porch, $7,630; Juan and Dora Jimenez, 1405 Jeronimo Ct., new residence, $185,358; Charles W. and Mary E Swetnam, 52 Calle Maria Elena, new swimming pool, $11,900.

Santa Cruz County

2 residents
1 guest house

Hacienda Amado LLP, 158 Casa Blanca Canyon Rd., Sonoita, remodel main house, add guest house, $500,000; Thomas and Barbara Dinwiddie, 230 Lake Patagonia, Patagonia, temporary electric permit; Penny and Ken Niemi, 102 Ave. de Otero, Tubac, living room addition, $78,529; Donald and Carol Shelton, 215 Aliso Springs Rd., Tubac, addition, $76,422; William and Jeremy Hutchinson, 2 Wood Canyon Dr., Patagonia, new storage building, $25,500; Lawyers Title, 67 Almendras Ct., Tubac, new residence, $235,157; Lawyers Title, 79 Palmas Ct., Tubac, residence, $185,990; Carrel Conley, 60 Hershaw Creek Rd., Patagonia, electrical permit; Ken and Lori Kaiser, 19 Calle Maria Elena, Tubac, new swimming pool and spa, $10,115; Baca Float Water Co., 2102 E. Frontage Rd., Tubac, electrical upgrade; Owner of Easement, 205 Ramada Trail, Tubac, electrical permit for pumping station, $40,000; Hanna's Hill Enterprises LLC, 3989 Highway 82, Elgin, new barn, $29,376; Keith D and Beth L Martin, 19 Milky Way, Sonoita, new wind turbine, $13,975; Alfred Daniel Martinez, 7 Javelina Ct., Sonoita, new barn, $33,264; Ann Meyers, 50 Sherwood Forest Lane, Sonoita, electrical permit; David and Krista Dunn, 15 Sundance Ct., electrical.

EXHIBIT M-5 Admitted

Santa Cruz County Population Projections 2006 - 2055

TABLE 1. Components of Population Change

Year	Population	Change	%Change	Net Migration	Change	%Change	Births	Change	%Change	Deaths	Change	%Change
2006	45,303	---	---	674	---	---	821	---	---	247	---	---
2007	46,545	1,242	2.741540%	647	-27	-4.005935%	854	33	4.019488%	259	12	4.858300%
2008	47,777	1,232	2.646901%	620	-27	-4.173107%	882	28	3.278689%	270	11	4.247104%
2009	48,998	1,221	2.555623%	590	-30	-4.838710%	914	32	3.628118%	283	13	4.814815%
2010	50,210	1,212	2.473570%	559	-31	-5.254237%	945	31	3.391685%	292	9	3.180212%
2011	51,418	1,208	2.405895%	536	-23	-4.114490%	974	29	3.068783%	302	10	3.424658%
2012	52,607	1,189	2.312420%	518	-18	-3.358209%	999	25	2.566735%	328	26	8.609272%
2013	53,800	1,193	2.267759%	510	-8	-1.544402%	1,016	17	1.701702%	333	5	1.524390%
2014	54,973	1,173	2.180297%	490	-20	-3.921569%	1,031	15	1.476378%	348	15	4.504505%
2015	56,144	1,171	2.130137%	481	-9	-1.836735%	1,045	14	1.357905%	355	7	2.011494%
2016	57,291	1,147	2.042961%	466	-15	-3.118503%	1,053	8	0.765550%	372	17	4.788732%
2017	58,412	1,121	1.956677%	448	-18	-3.862661%	1,056	3	0.284900%	383	11	2.956989%
2018	59,514	1,102	1.886599%	435	-13	-2.901786%	1,061	5	0.473485%	394	11	2.872063%
2019	60,595	1,081	1.816379%	421	-14	-3.218391%	1,067	6	0.565504%	407	13	3.299492%
2020	61,658	1,063	1.754270%	405	-16	-3.800475%	1,073	6	0.562324%	415	8	1.965602%
2021	62,699	1,041	1.688345%	398	-7	-1.728395%	1,076	3	0.279590%	433	18	4.337349%
2022	63,726	1,027	1.637985%	390	-8	-2.010050%	1,085	9	0.836431%	448	15	3.464203%
2023	64,728	1,002	1.572357%	377	-13	-3.333333%	1,092	7	0.645161%	467	19	4.241071%
2024	65,691	963	1.487764%	353	-24	-6.366048%	1,098	6	0.549451%	488	21	4.496788%
2025	66,627	936	1.424853%	334	-19	-5.382436%	1,103	5	0.455373%	501	13	2.663934%
2026	67,544	917	1.376319%	322	-12	-3.592814%	1,113	10	0.906618%	518	17	3.393214%
2027	68,444	900	1.332465%	311	-11	-3.416149%	1,125	12	1.078167%	536	18	3.474903%
2028	69,330	886	1.294489%	302	-9	-2.893891%	1,133	8	0.711111%	549	13	2.425373%
2029	70,192	862	1.243329%	276	-26	-8.609272%	1,149	16	1.412180%	563	14	2.550091%
2030	71,033	841	1.198142%	264	-12	-4.347826%	1,160	11	0.957354%	583	20	3.552398%
2031	71,863	830	1.168471%	247	-17	-6.439394%	1,175	15	1.293103%	592	9	1.543739%
2032	72,677	814	1.132711%	230	-17	-6.882591%	1,193	18	1.531915%	609	17	2.871622%
2033	73,463	786	1.081498%	207	-23	-10.000000%	1,208	15	1.257334%	629	20	3.284072%
2034	74,234	771	1.049508%	192	-15	-7.246377%	1,225	17	1.407285%	646	17	2.702703%
2035	74,986	752	1.013013%	179	-13	-6.770833%	1,237	12	0.979592%	664	18	2.786378%
2036	75,723	737	0.982850%	169	-10	-5.586592%	1,248	11	0.889248%	680	16	2.409639%
2037	76,449	726	0.958758%	155	-14	-8.284024%	1,265	17	1.362179%	694	14	2.058824%
2038	77,157	708	0.926108%	144	-11	-7.096774%	1,273	8	0.632411%	709	15	2.161383%
2039	77,846	689	0.892984%	127	-17	-11.805556%	1,284	11	0.864101%	722	13	1.833568%
2040	78,526	680	0.873520%	118	-9	-7.086614%	1,295	11	0.856698%	733	11	1.523546%
2041	79,185	659	0.839212%	107	-11	-9.322034%	1,303	8	0.617761%	751	18	2.455662%
2042	79,821	636	0.803182%	88	-19	-17.757009%	1,310	7	0.537222%	762	11	1.464714%
2043	80,455	634	0.794277%	91	3	3.409091%	1,315	5	0.381679%	772	10	1.312336%
2044	81,081	626	0.778075%	90	-1	-1.098901%	1,320	5	0.380228%	784	12	1.554404%
2045	81,696	615	0.758501%	85	-5	-5.555556%	1,324	4	0.303030%	794	10	1.275510%
2046	82,301	605	0.740550%	77	-8	-9.411765%	1,328	4	0.302115%	800	6	0.755668%
2047	82,909	608	0.738752%	79	2	2.597403%	1,333	5	0.376506%	804	4	0.500000%
2048	83,509	600	0.723685%	73	-6	-7.594937%	1,338	5	0.375094%	811	7	0.870647%
2049	84,107	598	0.716090%	74	1	1.369863%	1,341	3	0.224215%	817	6	0.739827%
2050	84,708	601	0.714566%	76	2	2.702703%	1,345	4	0.298285%	820	3	0.367197%
2051	85,312	604	0.713038%	74	-2	-2.631579%	1,356	11	0.817844%	826	6	0.731707%
2052	85,915	603	0.706817%	66	-8	-10.810811%	1,369	13	0.958702%	832	6	0.726392%
2053	86,519	604	0.703020%	62	-4	-6.060606%	1,376	7	0.511322%	834	2	0.240385%
2054	87,130	611	0.706203%	57	-5	-8.064516%	1,387	11	0.799419%	833	-1	-0.119904%
2055	87,749	619	0.710433%	63	6	10.526316%	1,397	10	0.720981%	841	8	0.960384%

Source: Arizona Department of Economic Security, Research Administration, Population Statistics Unit. (602)542-5984
Population projected by Demographic Cohort-Component Population Model. Fax (602)542-7425
Approved by Arizona Department of Economic Security Director March 31, 2006

EXHIBIT
M-6
(Admin. Notice)

UNISOURCE ENERGY CORPORATION **APPENDIX C**

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

RATE COMPONENTS

		$/kWh	
Current PPFAC Base Rate			
Cost of Electric Generation		$0.04802	\1
Cost of WAPA Transmission		$0.00392	\1
Total Current Rate		$0.05194	
Increase in Cost of Generation			
APS contract cost of generation (a)	(a)	$0.05879	\1
Loss Factor (b)	(b)	10.69%	\1, \2
Cost of Electric Generation at Meter	a / (1 - b)	$0.06583	
Increase in Cost of Generation		$0.01781	
Increase in WAPA Transmission			
Increase in WAPA Transmission		$0.00044	\1
Current Cost of WAPA Transmission		$0.00436	\1
PPFAC Adjustor Rate		**$0.01825**	

\1 Citizens' Amended Application for the Purchased Power and Fuel Adjustment Clause dated September 19, 2001.

\2 Approved Losses Rate from Citizens' last rate case.

3. For the purposes of determining a reasonable installment payment schedule under these rules, the utility and the customer shall give consideration to the following conditions:
   a. Size of the delinquent account,
   b. Customer's ability to pay,
   c. Customer's payment history,
   d. Length of time that the debt has been outstanding,
   e. Circumstances which resulted in the debt being outstanding, and
   f. Any other relevant factors related to the circumstances of the customer.
4. Any customer who desires to enter into a deferred payment agreement shall establish such agreement prior to the utility's scheduled termination date for nonpayment of bills. The customer's failure to execute such an agreement prior to the termination date will not prevent the utility from disconnecting service for nonpayment.
5. Deferred payment agreements may be in writing and may be signed by the customer and an authorized utility representative.
6. A deferred payment agreement may include a finance charge as approved by the Commission in a tariff proceeding.
7. If a customer has not fulfilled the terms of a deferred payment agreement, the utility shall have the right to disconnect service pursuant to the utility's termination of service rules. Under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

I. Change of occupancy
1. To order service discontinued or to change occupancy, the customer must give the utility at least three working days advance notice in person, in writing, or by telephone.
2. The outgoing customer shall be responsible for all utility services provided or consumed up to the scheduled turn-off date.
3. The outgoing customer is responsible for providing access to the meter so that the utility may obtain a final meter reading.

Historical Note

Adopted effective March 2, 1982 (Supp. 82-2). Amended by an emergency action effective August 10, 1998, pursuant to A.R.S. § 41-1026, in effect for a maximum of 180 days (Supp. 98-3). Emergency amendment replaced by exempt permanent amendment effective December 31, 1998 (Supp. 98-4). Amended by exempt rulemaking at 5 A.A.R. 3933, effective September 24, 1999 (Supp. 99-3).

Editor's Note: The following Section was amended under an exemption from the Attorney General approval provisions of the Arizona Administrative Procedure Act (State ex. rel. Corbin v. Arizona Corporation Commission, 174 Ariz. 216 848 P.2d 301 (App. 1992)), as determined by the Corporation Commission. This exemption means that the rules as amended were not approved by the Attorney General.

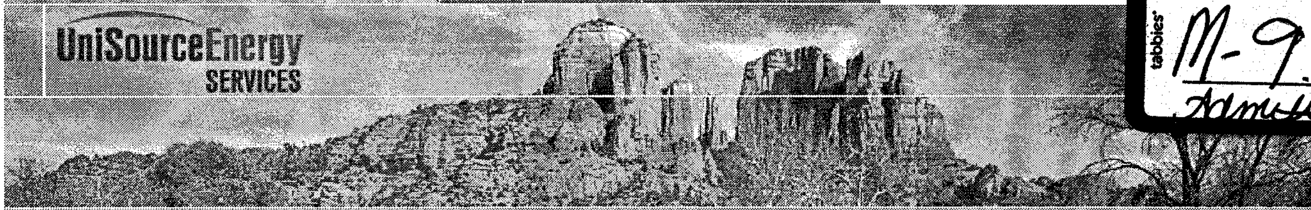
R14-2-211. Termination of Service

A. Nonpermissible reasons to disconnect service. A utility may not disconnect service for any of the reasons stated below:
1. Delinquency in payment for services rendered to a prior ~~customer at the premises where~~ service is being provided, except in the instance where the prior customer continues to reside on the premises.
2. Failure of the customer to pay for services or equipment which are not regulated by the Commission.
3. Nonpayment of a bill related to another class of service.
4. Failure to pay for a bill to correct a previous underbilling due to an inaccurate meter or meter failure if the customer agrees to pay over a reasonable period of time.
5. A utility shall not terminate residential service where the customer has ~~an inability~~ to pay and:
   a. The customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination would be especially dangerous to the health of a customer or a permanent resi~~dent residing on the customer's~~ premises, or
   b. Life supporting equipment used in the ~~home that~~ is dependent on utility service for operation of such apparatus, or
   c. Where weather will be especially dangerous to health as defined or as determined by the Commission.
6. ~~Residential service to ill, elderly,~~ or handicapped persons who have an inability to pay will not be terminated until all of the following have been attempted:
   a. The customer has been informed of the availability of funds from various government and social assistance agencies of which the utility is aware.
   b. A third party previously designated by the customer has been notified and has not made arrangements to pay the outstanding utility bill.
7. A customer utilizing the provisions of subsection (A)(4) or (A)(5) above may be required to enter into a deferred payment agreement with the utility within 10 days after the scheduled termination date.
8. Disputed bills where the customer has complied with the Commission's rules on customer bill disputes.

B. Termination of service without notice
1. In a competitive marketplace, the Electric Service Provider cannot order a disconnect for nonpayment but can only send a notice of contract cancellation to the customer and the Utility Distribution Company. Utility service may be disconnected without advance written notice under the following conditions:
   a. The existence of an obvious hazard to the safety or health of the consumer or the general population or the utility's personnel or facilities.
   b. The utility has evidence of meter tampering or fraud.
   c. Failure of a customer to comply with the curtailment procedures imposed by a utility during supply shortages.
2. The utility shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the utility.
3. Each utility shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one year and shall be available for inspection by the Commission.

C. Termination of service with notice
1. In a competitive marketplace, the Electric Service Provider cannot order a disconnect for nonpayment but can only send a notice of contract cancellation to the customer and the Utility Distribution Company. A utility may disconnect service to any customer for any reason stated below provided the utility has met the notice requirements established by the Commission:
   a. Customer violation of any of the utility's tariffs,
   b. Failure of the customer to pay a delinquent bill for utility service,
   c. Failure to meet or maintain the utility's deposit requirements,

EXHIBIT
M-9
Admitted



Customer Service
- Account Manager
- Account Services
- **Billing & Payment Options**
  - **Payment Options**
  - Courtesy Payment Box Location
  - **Cash Payment Agent**
  - *UES e-bill*
  - Pricing plans
  - Budget Billing
  - SNAP
  - GreenWatts
  - Warm Spirit
  - Bill Inserts

Customer Service

Payment Agents

- ACE Cash Express Locations
- Additional Cash Only Locations

Cash only -

- You will be provided with a receipt after cash payment has been made.
- Please verify the accuracy of your account number on your receipt before leaving.
- Please take your bill stub with you. This will help make sure your payment is processed accurately.
- A $1.00 fee will apply at selected locations (see below).

ACE Cash Express Locations

Bullhead City

1812 Highway 95, Ste 20, Bullhead City, AZ 86442
(928) 763-8865
($1.00 fee will apply)

Store Hours: Monday through Thursday 8:30 a.m. to 6:30 p.m.; Friday 8:30 a.m. to 7:00 p.m.; Saturday 9 a.m. to 5 p.m.; Closed Sunday

Camp Verde

522 Finnie Flats Road, #F, Camp Verde, AZ 86322
(928) 567-0676

Store Hours: Monday through Friday 9:00 a.m. to 6:00 p.m.; Saturday 9:00 a.m. to 3:00 p.m.; Closed Sunday

Chino Valley

1578 N. US-89 Suite A, Chino Valley, AZ 86323
(928) 636-5545

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Cottonwood

989 S. Main, Ste B, Cottonwood, AZ 86326
(928) 639-1000

Store Hours: Monday through Friday 8:30 a.m. to 6:30 p.m.; Saturday 10:00 a.m. to 5:00 p.m.; Closed Sunday

Golden Valley

52 S. Hope #A1, Golden Valley, AZ 86431
(928) 565-5055
($1 fee will apply)

Store Hours: Monday through Thursday 10 a.m. to 6:00 p.m.; Friday 10 a.m. to 7 p.m.; Saturday 10:00 a.m. to 2:00 p.m.; Closed Sunday

Kingman

3787 Stockton Hill Road, Kingman, AZ 86401
(928) 692-7110
2785 Northern Ave, Kingman, AZ 86401

Account Manager

E-mail:

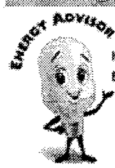
Password:

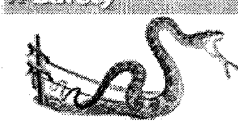
LOGIN

New user?
Learn more | **Enroll**

Forgot your password?

Tell a friend





(928) 757-7575
($1 fee will apply)

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Lake Havasu City

20 N. Acoma Blvd, Lake Havasu City, AZ 86403
(928) 854-4447

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Nogales

1965 N. Grand Ave., Nogales, AZ 85621
(520) 761-3999

Store Hours: Monday through Saturday 9:00 a.m. to 9:00 p.m.; Sunday 10:00 a.m. to 6:00 p.m.

570 W. Mariposa, Nogales, AZ 85621
(520) 377-2013
($1 fee will apply)

Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Sunday 9:00 a.m. to 4:00 p.m.

43 N. Morley Ave, Nogales, AZ 85621
(520) 287-7400
($1 fee will apply)

Store Hours: Monday through Saturday 10:00 a.m. to 6:00 p.m.; Sunday 10:00 a.m. to 4:00 p.m.

Prescott

621 Miller Valley Road, Prescott, AZ 86301
(928) 777-0039

Store Hours: Monday through Thursday 8:00 a.m to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Prescott Valley

8101 E. Hwy. 69, Ste A, Prescott Valley, AZ 86314
(928) 759-9939

Store Hours: Monday through Thursday 9:00 a.m. to 6:30 p.m.; Friday 9:00 a.m. to 7:00 p.m.; Saturday 9:30 a.m. 5:00 p.m.; Closed Sunday

Additional Cash Only Locations

Flagstaff

OA Quick Cash
3470 E. Route 66, Suite 101, Flagstaff AZ 86004
(928) 526-5626
Store Hours: Monday through Friday 9:00 a.m. to 5:30 p.m.; Saturday 10:00 a.m. to 2:00 p.m.; Closed Sunday

Winslow

Winslow Document Express
118 B E. Second St., Winslow AZ
(928) 289-3290
Store Hours: Monday through Friday 9:00 a.m. to 5:00 p.m.; Closed Saturday and Sunday

Show Low

Audio Advantage/Radio Shack
4431 S. White Mountain Rd., Suite 1, Show Low AZ 85901
(928) 532-0462
Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Closed Sunday

Sedona

Weber IGA Food & Drug
100 Verde Valley School, Sedona AZ 86351
(928) 284-1144
Store Hours: Monday through Saturday 6:00 a.m. to 10:00 p.m.;

NOAA's National Weather Service Weather Forecast Office

Pueblo, CO

Heat Index

About 237 Americans succumb to the taxing demands of heat every year*. Our bodies dissipate heat by varying the rate and depth of blood circulation, by losing water through the skin and sweat glands, and as a last resort, by panting, when blood is heated above 98.6°F. Sweating cools the body through evaporation. However, high relative humidity retards evaporation, robbing the body of its ability to cool itself.

When heat gain exceeds the level the body can remove, body temperature begins to rise, and heat related illnesses and disorders may develop.

The **Heat Index** (HI) is the temperature the body feels when heat and humidity are combined. The chart below shows the HI that corresponds to the actual air temperature and relative humidity. (This chart is based upon shady, light wind conditions. **Exposure to direct sunlight can increase the HI by up to 15°F.)**

(Due to the nature of the heat index calculation, the values in the tables below have an error +/- 1.3F.)

Temperature (F) versus Relative Humidity (%)

°F	90%	80%	70%	60%	50%	40%
80	85	84	82	81	80	79
85	101	96	92	90	86	84
90	121	113	105	99	94	90
95		133	122	113	105	98
100			142	129	118	109
105				148	133	121
110						135

HI	Possible Heat Disorder:
80°F - 90°F	Fatigue possible with prolonged exposure and physical activity.
90°F - 105°F	Sunstroke, heat cramps and heat exhaustion possible.
105°F - 130°F	Sunstroke, heat cramps, and heat exhaustion likely, and heat stroke possible.
130°F or greater	**Heat stroke highly likely with continued exposure.**

NOAA's National Weather Service Weather Forecast Office

Pueblo, CO

EXHIBIT
tabbies
M-11
Admitted

Heat Index

About 237 Americans succumb to the taxing demands of heat every year*. Our bodies dissipate heat by varying the rate and depth of blood circulation, by losing water through the skin and sweat glands, and as a last resort, by panting, when blood is heated above 98.6°F. Sweating cools the body through evaporation. However, high relative humidity retards evaporation, robbing the body of its ability to cool itself.

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80	85	84	82	81	80	79
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95		133	122	113	105	98
100			142	129	118	109
105				148	133	121
110						135

HI	Possible Heat Disorder:
80°F - 90°F	Fatigue possible with prolonged exposure and physical activity.
90°F - 105°F	Sunstroke, heat cramps and heat exhaustion possible.
105°F - 130°F	Sunstroke, heat cramps, and heat exhaustion likely, and heat stroke possible.
130°F or greater	**Heat stroke highly likely with continued exposure.**

Below is a table comparing Temperature and Dewpoint, with the same disorders possible:
Temperature (Down) versus Dewpoint (across)

°F	55	60	65	70	75	80	85
80	80	80	81	83	84	87	
85		84	86	89	93	99	107
90			91	95	100	107	117
95				101	106	114	125
100					113	121	131
105						127	138
110						134	145

Other Links:

- Heat Wave - A Major Summer Killer (.pdf)
- Heat Index Equation - NWS Birmingham, AL
- NWS Heat and Drought Awareness Page
- The Heat Index Equation - Technical Attachment (PDF)

* 10-year average of heat related fatalities from 1994-2003. U.S. Natural Hazard Statistics.

NOAA's National Weather Service
Pueblo, CO Weather Forecast Office
3 Eaton Way
Pueblo, CO 81001-7326
(719) 948-9429
Page Author: PUB Webmaster
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Page last modified: 22-Feb-2006 10:33 PM UTC

B.Y.O. BRAIN

EXHIBIT
M-12
Admitted

⁾lanting 1,000 trees is certain to ma... ...ence

n honor of National Make A ference Day on Oct. 27, the ızona Daily Star, Citi, Cox nmunications, Tucson Elec- : Power, and Tucson Clean l Beautiful are hosting a proj- to plant 1,000 native trees all und Tucson. That's a lot of ₃s.

⁾id you know that trees create ɔitats (places to live) for ani- ls, provide cleaner air and ·er temperatures?

ɩccording to the Arbor Day ındation, here are some other l tree facts:

Trees provide cooling sum- ɾ shade and reduce air condi- ıing costs.

Communities with trees can ɩs much as 12 degrees cooler he summer than those with- the protection trees provide. In winter, trees slow cold ıds and reduce heating costs. Being able to see trees out- ₃ a hospital window has been wn to help patients heal er. A view of trees can also reduce stress in the workplace.

▸ Trees help discourage vandalism, graffiti, and violence.

MY TREE CONTEST

Submit your artwork by 5 p.m. Oct. 15 to:

Sharon Foltz, Community Relations Director
Tucson Electric Power Company
UniSource Energy Gas & UniSource Energy Electric
P.O. Box 711 - UE102
Tucson, AZ 85702

or drop off your entry at Tucson Electric Power, 1 S. Church Ave.

* All artwork becomes the property of Tucson Clean & Beautiful.

My Tree for Tucson

To help celebrate the 1,000 Trees for Tucson campaign, Tucson Clean & Beautiful is hosting an art contest called My Tree for Tucson.

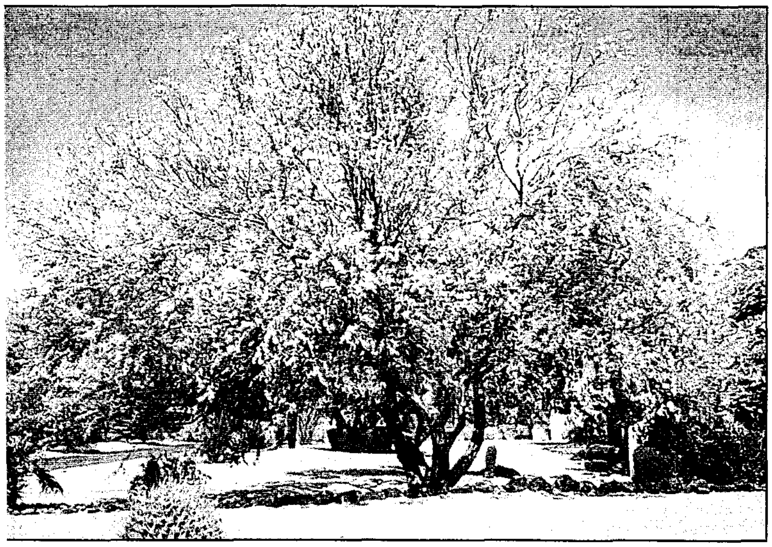
Draw, paint or take a photo showing what your favorite tree looks like and what activities you like to do in, around or under your tree. Do you read a book under your tree? Set up a tent under a tree when camping? Take a ride on a swing hung from a tree's branch?

For the winner, to be chosen on Oct. 18:

▸ A $50 gift certificate to the Kid's Center, 1725 N. Swan Road.

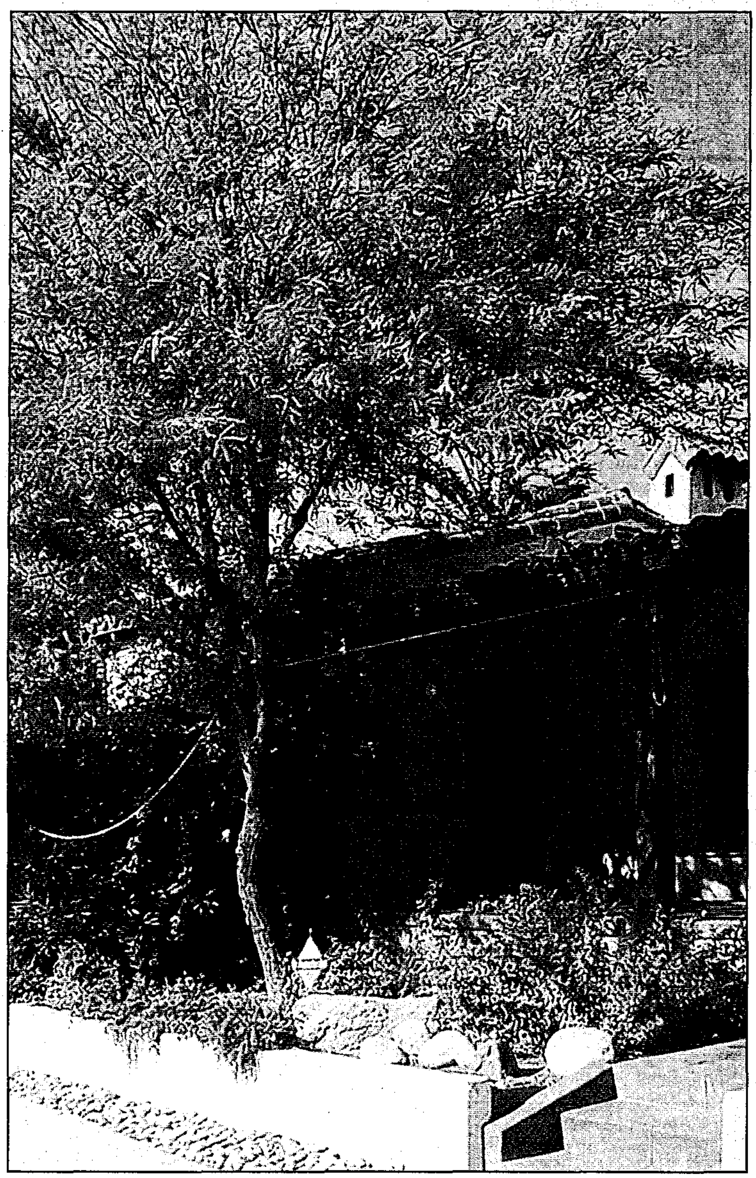
▸ The artwork will be displayed and he or she will help Mayor Bob Walkup plant a tree at the 1,000 Trees for Tucson kickoff ceremony on Oct. 27 at the Thomas Jay Regional Park and Littletown Recreation Center, 6465 S. Craycroft Road.

▸ The artwork will be used as part of the national nomination for Make a Difference Day and possibly used for future Trees for Tucson event.



PHOTOS COURTESY OF TUCSON CLEAN & BEAUTIFUL

desert willow in bloom is a dramatic tree that adds color as well as beauty to any landscape.



Mesquites offer shade in addition to being a source of food with their many seed pods.

Allowable Trees

EXHIBIT
M-13
(Admin. Notice)

ARTICLE 29 – LOW WATER USE/DROUGHT TOLERANT PLANT LIST
----2900----GENERAL
----2901----RECOMMENDED PLANT LIST
----2902----PROHIBITED PLANT LIST
SEC. 2900 GENERAL

The plants on this list should prosper in the Santa Cruz County area with moderate to no supplemental irrigation once they are established. Occasionally, for good appearance, supplemental irrigation may be applied. All the plants use less water than traditional high water use landscape plants, and this list provides a variety to accomplish any landscape design need.

Applications for additions, deletions, or exceptions to the list may be submitted to the Department of Community Development for consideration. Santa Cruz County forbids the use of any non-native species known to be invasive. See accompanying list of prohibited invasive species. [not included]

Santa Cruz County strongly discourages the use of any species with know toxicity (*).

Highly flammable plants (D) must not be planted within 30 feet of any flammable structure. This distance must be increased enough to allow for the expected mature size of plant.

Plants known to produce pollen that is strongly or moderately allergenic (a,b) should be used sparingly, if at all.

	Botanical Name	**Common Name**
S	*Calliandra eriophylla* 1 R	Fairy duster, False mesquite
T	*Cercidium floridum* 2-3 (sh) (t)	Blue palo verde
T	*Cercidium microphyllum* 1-2 (sh) (t)	Littleleaf or Foot-hill palo verde
T	*Carcidium x sonorae* 1-2 (sh) (t)	Sonoran palo verde
T c	*Parkinsonia aculeata* 1-2 (t)	Mexican palo verde
T b	*Prosopis chilensis* 1-2	Chilean mesquite
T b	*Prosopis velutina* 1-2	Velvet mesquite

Ref: Santa Cruz County Zoning and Development Code, 2006, Article 29 – Low Water Use/Drought Tolerant Plant List

Symbols

Water needs:

1 = No supplemental irrigation once established
2 = Once a month in warm weather once established
3 = Twice a month in warm weather once established

Medical Alert:

b = Known or suspected to be moderately allergenic
c. = Known or suspected to be allergenic for some individuals or produces a wind-born pollen of unknown allergenicity

Life Form:

S = Shrub
T = Tree

Frost Tolerance:

(sh) = Semi-hardy, Some dieback in a hard frost
(t) = Tender, unsuitable for climate

Fire Impact"

R = flame resistant, good for fire protection

Tucson Citizen

EXHIBIT
M-14

Ariz. last in utility assistance funds

Warm temps said to work against state
The Arizona Republic
Published: 09.05.2007

Nearly a quarter of the year, the mercury in Arizona hits 100 or higher.

But those scorching days do little to qualify the state for federal funding marked to help low-income residents afford to keep their homes cool during the summer.

Arizona received the least amount of funding per low-income person in the nation through the Low Income Home Energy Assistance Program in 2006, according to Cynthia Zwick, director of the Community Action Association.

The program's funding is funneled to cities, agencies and counties by the Arizona Department of Economic Security.

This means the state could serve only about 4 percent of families who qualified for help in 2005, Zwick said.

"We run out every single month. As many folks as we can serve, there are many more out there that we can't," Zwick said.

The association is an advocacy group that promotes economic self-sufficiency for low-income people.

The program's money is given to states every year through the federal budget.

The formula Congress uses to determine how much money states receive originally favored cold-weather areas, Zwick said. Because of that, Arizona receives less money than other Western states because there are few days with low temperatures.

This year, Arizona received $7.4 million in program funding, while Texas was allotted $44 million.

Stressing equality

Rep. Harry Mitchell, D-Ariz., said cold-weather and hot-weather states should be funded equally in the program.

"It's a good program," Mitchell said. "There just needs to be an equal emphasis."

Mitchell's office said the House of Representatives moved legislation in July that detailed a $501 million increase for the program. The legislation has moved to the Senate for further consideration.

U.S. Sen. Jon Kyl, R-Ariz., has also voiced frustration over the program's funding.

"The Senate should recognize what Arizonans know all too well: Extremely high temperatures can pose just as much of a risk to health as cold weather does," Kyl said in 2006 before the Senate approved legislation that his office said helped ensure a more equal distribution of the program's funds.

Kyl's office said the 2006 bill that was signed into law helped reshape the formula used to determine how much money each state gets under the program.

His staff said that the senator pushed for total home-energy costs to be factored into the formula, as well as concentrating funds on groups in need.

When it comes to ensuring that Arizona sees more funding in the future, Ryan Patmintra, press secretary for Kyl, said the office would closely monitor the issue.

Other funding sources

To qualify for federal assistance, a family must be under 150 percent of the federal poverty level.

For a family of four, this would mean earning less than $30,975 a year.

Once a family receives help, it cannot get assistance again for 12 months.

Mary Hutchinson, director of Tempe's Community Action Agency, which controls the city's funds from the energy program, said it's challenging to serve people who are over the income level.

When someone who doesn't qualify seeks help, Hutchinson said they use funds from the city.

Yvette Patterson of the Mesa Community Action Network said the organization helped 2,037 households last year with their utility bills and spent an average of $233 on each household. She said the busy months for energy assistance are now through the start of October.

"A lot of families in low-income eligibility spend as much in utility cost as rental cost," she said.

Though there is no money for low-income energy assistance handed down in the state budget, Southwest Gas Corp. offers a 20 percent reduction on gas bills from October to April for limited-income customers.

Enclosure (2)

EXHIBIT
M-15
Admitted

Recommendations
From

Utilities and Payday Lenders:
Convenient Payments, Killer Loans[87]

1. `State regulators should prohibit utilities or their agents from entering into arrangements to pay for bill collection services from financial service companies or other lenders that lend money at exorbitant rates (typically, an annual percentage rate above 36 percent).

2. `State regulators should require utilities to maintain company operated and staffed service centers, including counters for in-person bill payments using cash, at locations convenient for customers throughout utility service territories.

3. `Regulators should allow utilities to sign contracts for bill payment services at additional locations that enhance convenience for customers but only with supermarkets, drug stores, convenience stores, other retail outlets, community groups and banks or other financial service providers that do not lend money at exorbitant rates.

4. Regulators should require utilities to verify the eligibility of all retail service providers to act as bill payment agents. Utilities should be required to verify that all authorized or unauthorized bill payment agents from whom utilities accept payment do not hold licenses that allow them to lend money at exorbitant rates.

5. `When utilities accept payments from third parties that offer bill payment services to customers but have no contracts with utilities, regulators should require utilities to receive from those agents certifications that they have charged customers no more than a nominal amount (typically, $1 or 1 percent of the amount due, whichever is lower) for bill payment, and that those customers have not been solicited to take out loans.

6. `Utilities should only be allowed to close down company operated and staffed service centers if they can demonstrate that the cost of those centers would put an unreasonable burden on ratepayers.

7. `State and federal laws and financial services regulations should prohibit lenders who collect utility bill payments from promoting or soliciting lending services before, during or after the transaction, and from lending money at exorbitant rates for use in utility bill payments.

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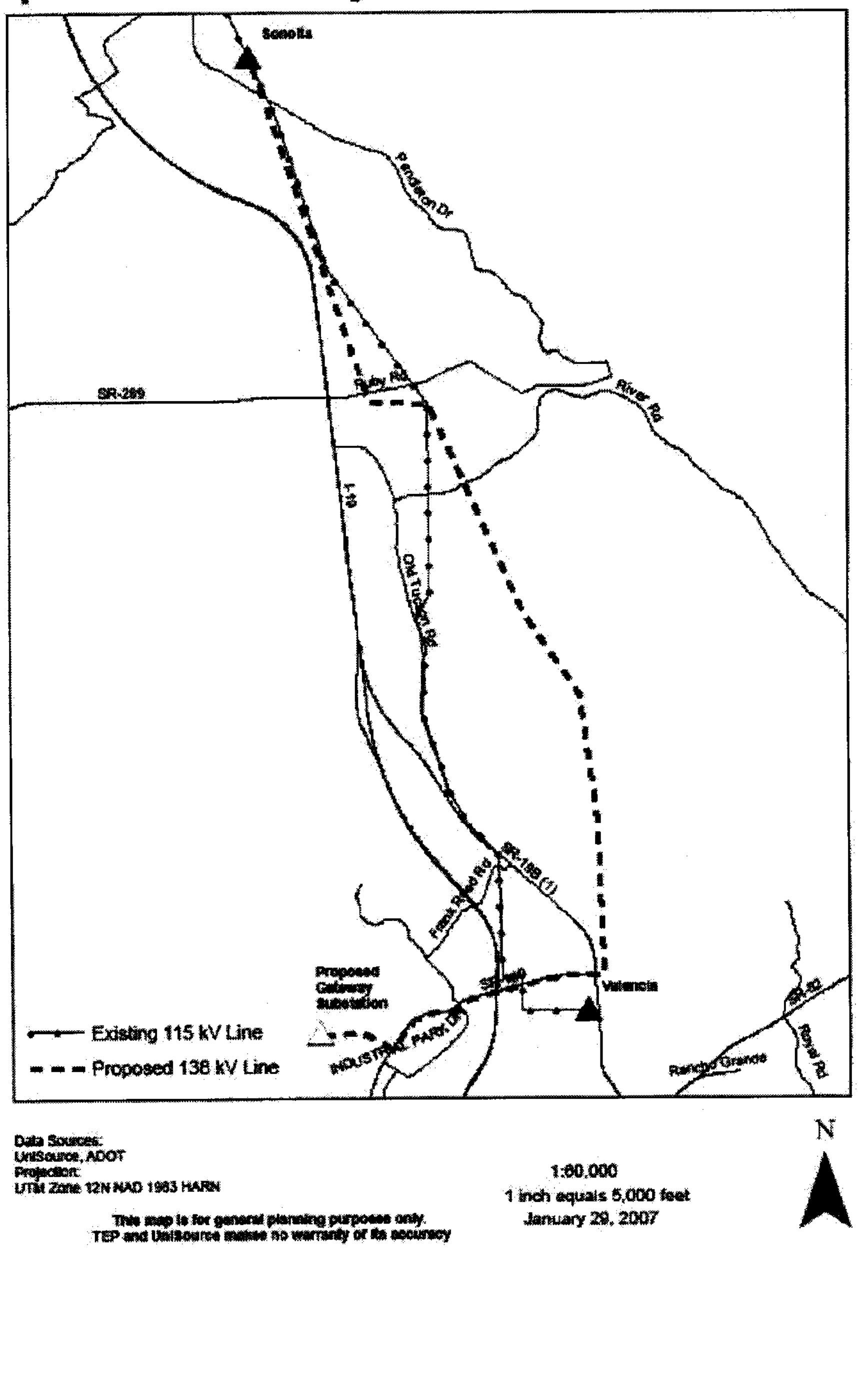
[87] By the National Consumer Law Center, 77 Summer Street, 10th Floor, Boston, MA 02110 www.consumerlaw.org June 2007, at 27-28.

EXHIBIT
tabbies
M-17
Admitted

Proposed Gateway to Sonoita 138 kV Line



Data Sources:
UniSource, ADOT
Projection:
UTM Zone 12N NAD 1983 HARN

This map is for general planning purposes only.
TEP and UniSource makes no warranty of its accuracy

1:60,000
1 inch equals 5,000 feet
January 29, 2007

STF 13.40

EXHIBIT
tabbies
M-18
Admitted

UNS Electric, Inc.

Test Year
Annual Report on
Environmental Portfolio Standard Programs

Prepared for:
Arizona Corporation Commission

July 1, 2005 – June 30, 2006

EPS Activity Summary

Pursuant to the Arizona Corporation Commission ("Commission") Order in Docket No. E-04204A-04-0304, Decision No. 67178, UNS Electric, Inc., a subsidiary of UniSource Energy Services ("UNS Electric") (formerly Citizens Communication Company, Mohave Electric Division and Santa Cruz Electric Division ["Citizens"]) presents an interim report on Environmental Portfolio Standard ("EPS") programs for the test year period covering July 1, 2005 through June 30, 2006.

Based on the percentage requirements of the portfolio standard, the following chart of MWh requirements has been used to forecast the UNS Electric EPS annual renewable energy needs:

EPS MWh Requirements

Year	UNSE/Citizens' Retail MWh Sales	EPS %	EPS MWh Required	Accumulated EPS MWh Required
Actual				
2001	1,275,036	0.20	2,550	2,550
2002	1,136,581	0.40	4,546	7,096
2003	1,392,466	0.60	8,355	15,451
2004	1,462,633	0.80	11,701	27,152
H1 2005	688,184	1.00	6,882	34,034
H2 2005	832,763	1.00	8,328	42,362
H1 2006	746,749	1.05	7,840	50,202
H2 2006	864,671	1.05	9,079	59,281
Projected				
2007	1,659,763	1.10	18,257	77,538
2008	1,709,555	1.10	18,805	96,343
2009	1,760,842	1.10	19,369	115,712
2010	1,813,667	1.10	19,950	135,662
2011	1,868,077	1.10	20,549	156,211
2012	1,924,120	1.10	21,165	177,376
Total	19,135,107		177,376	996,970

Surcharge revenues and program expenditures applicable for the test year July 1, 2005 through June 30, 2006 are summarized in Table 1. EPS energy totals for the test year and program to date are shown in Table 2. The energy (kWh) output from UNS Electric's on-site photovoltaic stations is outlined in Table 3.

Table 1

Summary of EPS Programs
Period from July 1, 2005 through June 30, 2006

Summary of Program Revenues			
Description	Thru 6/30/05	Period 7/1/05 - 6/30/06	Life of Program
GreenWatts Total	$1,794	$5,296	$7,090
Renewables Surcharge Total	$1,966,071	$538,502	$2,504,573
Total EPS Program Revenues	$1,967,865	$543,798	$2,511,663
Summary of Program Expenditures			
Hardware Buydown Program	$13,590	$120,649	$134,239
Landfill Gas Credits	$317,000	$150,000	$467,000
Marketing	$19,235	$902	$20,137
Materials & Supplies	$0	$167	$167
Outside Services & Contracting	$0	$2,923	$2,923
Payroll	$12,619	$27,880	$40,499
TEP Support Services	$9,487	$0	$9,487
Training & Travel	$967	$1,458	$2,425
Total EPS Renewables Expenditures	$372,898	$303,979	$676,877
Program Balance			
	$1,594,967	$239,819	$1,834,786

Table 2

Summary of EPS Energy Totals
Period from July 1, 2005 through June 30, 2006

Description	Cumulative Thru 6/30/05	Reporting Period 7/1/05 Thru 6/30/06	Cumulative Thru 6/30/06
Retail Sales, kWh	4,449,163,000	1,579,512,000	6,028,675,000
UES EPS Requirement (832,762,598 at 1.00% of retail sales for 2005), kWh	20,345,274	8,327,626	28,672,900
UES EPS Requirement (746,748,681 at 1.05% of retail sales for 2006), kWh	28,672,900	7,840,861	36,513,761
"Other" Credits Needed To Meet EPS Requirements(40% in 2005 and 2006), kWh	11,136,073	6,467,395	17,603,468
"Solar Electric" Resource Credits Needed to Meet EPS Requirements.(60% in 2005 and 2006), kWh	16,704,110	9,701,092	26,405,202
"Solar Electric" Resource Credits Generated, kWh (Note 1)	312,866	109,164	422,030
"Solar Electric" Resource Credits Purchased, kWh (Note 1)	0	0	0
"Other" Credits Generated, kWh	0	0	0
"Other" Credits Purchased, kWh	12,680,000	6,000,000	18,680,000
Total "Solar Electric" Credits, kWh	337,476	109,164	446,640
Total "Other " Credits, kWh	12,680,000	6,000,000	18,680,000
Excess "Solar Electric" Credits Above Meeting EPS Requirements, kWh	-16,290,916	-16,698,720	-32,989,636
Excess "Other" Credits Above Meeting EPS Requirements, KWH	1,819,200	162,036	1,981,236

(Note 1) Includes extra credit multiplier, 2.0 for 2005 and 2006

Table 3

EPS Solar Energy Production
Period from July 1, 2005 through June 30, 2006

KG	LH	NO	
	2342		
1476			
	3035		
8074			
2845			
	4406		
	2380		
	482		
	1114		
	3221		
	2124		
	1388		
	2937		
	817		
3555			
	571		
1041			
2247			
2741			
	697		
	3818		
3271			
25,250	**29,332**		kWh
		54,582	kWh

Total actual kWh generated for the test year:
54,582* 2.0 multiplier (in-state credits, distributed generation) = 109,164 kWh

Cumulative Solar kWh generated:

Year	kWh	Multipliers .5 Early Installation .5 In-State Installation .5 Distributed Generation	Total EPS kWh
1998	19,000	2.5	47,500
1999	19,000	2.5	47,500
2000	19,000	2.5	47,500
2001	19,000	2.5	47,500
2002	19,400	2.5	47,500
2003	13,333	2.0 (Early Install Multiplier Ended)	26,700
2004	9,978	2.0	19,956
H1 2005	14,433	2.0	28,866
H2 2005	12,305	2.0	24,610
H1 2006	42,277	2.0	84,554
H2 2006	68,318	2.0	136,636
Total			558,822

SOLAR PROJECTS TO DATE

Two solar projects were initiated in 1997. The two systems installed by Citizens were part of a pilot project undertaken in partnership with a TEAM-UP utility working group. The group received funds from the federal Department of Energy through a partnering program with the Utility Photo Voltaic Group.

This solar project includes two sites:

Lake Havasu City:

- 2 Systems
- Each system comprised of 12 panels for a total of 24 panels
- Site output is approximately 4 kW
- Grid connected (no battery storage)

Kingman:

- 2 systems
- One system is comprised of 13 panels, the other has 14 for a total of 27 panels
- Site output is approximately 4 kW
- Grid connected (no battery storage)

In addition, to further meet the EPS requirements, UNS Electric purchased 6,000 MWh of Landfill Gas Credits from Tucson Electric Power (TEP), issued under EPS Credit Certificate No. TEP/UNSE - 003. With this purchase, UNS Electric will carry a credit surplus of 1,981 MWh of "Other" credits into the second half of 2006.

UNS Electric received approval from the Arizona Corporation in August 2004 for the GreenWatts and SunShare Programs. Since the inception of the SunShare Program, twenty customers have received $120,649 in subsidies through June 2006.

JNS Electric, Inc.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/18/2007	End of 2006/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in is page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated s a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend ore than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a erm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost er unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one el is burned in a plant furnish only the composite heat rate for all fuels burned.

EXHIBIT
M-20
Admitted

ne No.	Item (a)	Plant Name: *VALENCIA* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor					
3	Year Originally Constructed	1989					
4	Year Last Unit was Installed	2006					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	61.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	59			0		
7	Plant Hours Connected to Load	115			0		
8	Net Continuous Plant Capability (Megawatts)	61			0		
9	When Not Limited by Condenser Water	61			0		
10	When Limited by Condenser Water	61			0		
11	Average Number of Employees	4			0		
12	Net Generation, Exclusive of Plant Use - KWh	1744344			0		
13	Cost of Plant: Land and Land Rights	765874			0		
14	Structures and Improvements	1969407			0		
15	Equipment Costs	24393648			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	27128929			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	444.7365			0.0000		
19	Production Expenses: Oper, Supv, & Engr	346375			0		
20	Fuel	159980			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	54911			0		
30	Maintenance of Structures	59277			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	241511			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	862054			0		
35	Expenses per Net KWh	0.4942			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Diesel				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Gallons				
38	Quantity (Units) of Fuel Burned	22908	19005	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1015	120000	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.324	2.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.324	2.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5245.641	16.667	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	6.928	0.022	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	1320.750	0.000	0.000	0.000	0.000	0.000

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT

M-21

Admitted

COMMISSIONERS

Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC.	**Docket No. E-04204A-06-0783** **A Motion to Intervene**

As provided by the Procedural Order of 1 February 2007, Marshall Magruder, a Santa Cruz County UNS Electric, Inc. customer, respectfully requests to intervene in this case. Some of the areas of interest include the

a. Proposed base rate increases since the 21% rate increase in August 2003,

b. *Mandatory* Time of Use (TOU) tariffs for new residential and small commercial ratepayers including implementation policies for automated metering,

c. Modified *rate structure* including a proposed an overall rate of return of 9.89%,

d. Proposed Purchase Power and Fuel Adjustment Clause (PPFAC) rate structure,

e. New purchase power, generation and transmission agreements ratepayer impacts,

f. New generation resources in Nogales for proposed forecasted demand and future impacts, if any, on Reliability Must Run in Santa Cruz County,

g. Compliance with various ACC Orders including a City of Nogales Agreement impacts on *system reliability* in Santa Cruz County service area since the last rate case,

h. Proposed Demand Side Management (DSM) program including specified demand reduction performance measurement goals and plans for all rate categories,

12 N

i. Prudency of its existing DSM Program since the last rate case,

j. Conservation principles proposed for all rate payers including energy audits and provision of cost-effective energy efficient devices for low income ratepayers,

k. Effectiveness of the ACC *Environmental Portfolio Standard* since the last rate case,

l. Implementation of the *Renewable Energy Standard and Tariff* for all rate categories,

m. Proposed rate policies may blur a clear separation of "cost of service" and "cost of power" as the former is the primary profit mechanism for this distribution utility,

n. Potential for any Citizens-UniSource transition of ownership costs to be absorbed by the customers beyond those in the Settlement Agreement, and

o. Potential for UNS Electricity, Inc. ratepayers to pay multiple or imprudent charges to UniSource Energy and its subsidiaries including increases in O&M and G&A.

I have a copy of effective Procedural Order and the UNS Electric Application, Testimonies, Errata and Supplemental Filings to date.

I understand the procedural schedule and will comply with the required filing dates.

Early approval of this Motion to Intervene is requested as a better understanding of the above various issues involved should be attainable during discovery.

I certify this filing has been mailed to the company and all known and interested parties shown in the Distribution List. My e-mail address is provided below.

Respectfully submitted on this 12th day of March 2007

MARSHALL MAGRUDER

By Marshall Magruder

Marshall Magruder
PO Box 1267
Tubac, Arizona 85646-1267
(520) 398-8587
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Distribution List

Original and 20 copies of the foregoing are filed this date with:

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Interested Parties (1 copy each) are filed this date by mail:

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  Bob Damon, Supervisor
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777 North Grand Avenue
Nogales, Arizona 85621-2262

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

EXHIBIT
M-22
Admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC.

Docket No. E-04204A-06-0783

Notice and Filing of the Direct Testimony of Marshall Magruder and Comments Pertaining to the Content of this Direct Testimony

28 June 2007

As provided by the Procedural Orders of 1 February 2007 and 25 June 2007, herein is the Direct Testimony of Marshall Magruder, a Santa Cruz County UNS Electric, Inc. ratepayer. A Supplemental Direct Testimony is anticipated on or before 12 July 2007 to contain the remaining direct testimony..

On 26 June 2007, the Procedural Order of 25 June 2007 was received by this party who has concentrated this testimony primarily on the Demand-Side Management (DSM) issue for reasons discussed later. This UNS Electric, Inc. (UNSE or UNS Electric) DSM issue must be presented. There was no real testimony on DSM Programs or the DSM Adjustor during a UNS Gas Rate Case. No matter how confusing the Applicants testimonies and documentation conflict and diverge, these important DSM programs must be aired and resolved so the UNSE DSM Adjustor rate can be determined objectively in these proceedings.

On 13 June 2007, the UNSE holding company, UniSource Energy Services (UES) which is not a public service company, filed the latest UNS Electric DSM Program Portfolio. This 13 June 2007 filing was NOT referenced in the 25 June 2007 Procedural Order and also has not been in any Applicant's testimony or entered in the record during this proceeding.

Even through this could be a concern beyond my purview, this Direct Testimony used the 13 June 2007 UES DSM filing as the basis for my DSM testimony herein.

In my opinion, the 13 June 2007 UES DSM filing is the only relevant UNSE DSM Program document with detailed information available for review and has superseded all others by UNSE, including that in UNSE's earlier Direct Testimony.

This party received no indication from anyone there was any consideration about bifurcating and deferring DSM issues for this round of direct testimony. Therefore, I may modify this as supplemental direct testimony by the 12 July 2007 due date, as permitted in the latest Procedural Order, even as I am file my DSM Testimony in this Direct Testimony.

Also, this party has received NO testimony from the Applicant that refers to a proposed USNE Portfolio Standard (EPS) and/or the Renewable Energy Standard and Tariff (REST) surcharge.

In view of recent rejection by UNSE on 19 June 2007 of key elements of a data request, discussed in this testimony, I need to defer my testimony related to (1) UNS Electric costs and expenses to provide reliable electricity in the Santa Cruz service area and (2) CARES and CARES-M Program issues. I expect this will be resolved with a new data request and plan on inclusion of my remaining direct by 12 July 2007.

I certify this filing has been mailed to the company and all known and interested parties shown in the Service List.

Respectfully submitted on this 28th day of June 2007

MARSHALL MAGRUDER

By Marshall Magruder

Marshall Magruder
PO Box 1267
Tubac, Arizona 85646-1267
(520) 398-8587
marshall@magruder.org

DIRECT TESTIMONY

OF

MARSHALL MAGRUDER

28 June 2007

**In the matter
of the**

**APPLICATION OF UNS ELECTRIC, INC.,
FOR THE APPROVAL OF THE
ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES
DESIGNED TO REALIZE A
REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE
PROPERTIES OF UNS ELECTRIC, INC.**

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DIRECT TESTIMONY OF MARSHALL MAGRUDER

PART I
BACKGROUND AND INTRODUCTION

1.1 Introduction.

Q. Please state your name, business address, and occupation.

My name is Peyton Marshall Magruder, Jr. I am a customer of UNS Gas and UNS Electricity, two energy public service companies that serve Santa Cruz County. I was Vice-Chairman of the Santa Cruz County/City of Nogales Energy Commission, and active in community projects including the AARP tax aide program.

I have several jobs including Senior Scientist and Information Systems Architect for Integrated Systems Improvement Services (ISIS), Inc. in Sierra Vista, Arizona, working with information warfare, systems architectures, electronic and communications intelligence systems, test plans, information assurance, cryptologic systems management, and information technology services. I am Systems Engineer and Training Systems consultant for Imagine CBT, Inc., at Raytheon Naval and Maritime Systems in San Diego doing systems engineering work with US and Royal Navy involving aircraft carriers and amphibious warfare ship's command, control, communications, computers, intelligence, surveillance and reconnaissance systems, and training systems.

Annually, between January and April 15, I am employed as Tax Advisor Level 3 for H&R Block, Inc, in Tucson, Arizona. I retired from Raytheon- Hughes Aircraft Company as a Senior Systems Engineer after nearly 18 years and as a Naval Officer for 25 years. Please see Exhibit A for additional work experience.

As an instructor, I taught for the University of Phoenix MBA courses "Operations Management for Total Quality" and "Managing R&D and Innovation Processes" in Nogales, Arizona, where all the students were from Mexican maquilladores, and in Tucson, Arizona.

I am the Vice President of the Martin B-26 Marauder Historical Society and serve as Fund Raising Chairman for an ongoing five-million dollar "Lasting Legacy" fund drive to endow the MHS International Archives and restore a B-26 Marauder aircraft at the Pima Air & Space Museum/Arizona Aerospace Foundation in Tucson.

I hold two Masters of Science degrees, one from the University of Southern California in Systems Management (MSSM) with specialties in Managing R&D and Human Factors and from US Naval Postgraduate School a MS in Physical Oceanography with emphasis on underwater acoustics. My BS is from the US Naval Academy.

My business address is PO Box 1267, Tubac, Arizona, 85646-1267.

1.2 Involvement in these Proceedings.

Q. Why are you involved in these proceedings?

A. Both my professional background and involvement in local energy issues have led me to intervene and participate during these proceedings.

I have over 40 years of engineering experience with that last few decades as a systems engineer as shown in the Marshall Magruder Resume in Exhibit A. A systems engineer is one who conceptualizes a system based on understanding its needs, its functions, and its expected results.

As I learned in my first class in a Systems Management course, a system usually is somewhere between an atom and the universe, each made up of subsystems and each being a subsystem of a larger system. A Systems Engineer looks at the big picture, including economic, environmental, functional, human factors, reliability, and cost issues when designing alternatives and a methodology to assess and select the best alternative to accomplish the task. As Exhibit A shows, many diverse kinds and types of systems have shaped my background with a continuous array of unique experiences.

Q. Have you previously testified before this Commission?

A. Yes, I have made appearances at ACC Open and Special Meetings and as a party in ACC Dockets:

a. Arizona Power Plant and Transmission Line Siting Case No. 111[1] (TEP's CEC Application);

b. Docket No. E-01032C-00-0951[2], the Citizens Purchase Power and Fuel Adjustment Clause (PPFAC) hearings;

c. Docket Nos. E-1033A-02-0914, E-01032C-02-0914 and G-01032C-02-0914[3], the UniSource-Citizens Acquisition hearings;

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[1] This case was before the Arizona Power Plant and Transmission Line Siting Committee, Case No. 111, and ACC Docket Nos. L-00000C-01-0111 and L-00000F-01-0111 was for "the matter of the joint Application of Tucson Electric Power Company and Citizens Communications Company, or their Assignee(s) for a Certificate of Environmental Compatibility for a proposed 345 kV transmission line system from Tucson Electric Power Company's existing South 345 kV Substation in ...Sahuarita, Arizona, to the proposed Gateway 345/115 kV Substation in ... Nogales Arizona, with a 115 kV interconnection to the Citizens Communications Company's 115 kV Valencia Substation in Nogales, Arizona, with a 345 kV transmission line from the proposed Gateway Substation to the International Border ...," submitted on 1 March 2001." This case resulted in ACC Decision No. 64356. I was an Intervenor and Party. Siting Case No. 111 has been reopened including ACC Decision No. 82011 that previously closed ACC Docket No. E-01032A-99-0401.

[2] This case was before the ACC "in the matter of the Application of the Arizona Electric Division of Citizens Communications Company to change the current purchase power and fuel adjustment clause rate, to establish a new purchase power and fuel adjustment clause bank, and to request approval of guidelines for the recovery and cost Incurred in connection with energy risk management initiatives," on 28 September 2000.This was reflected in ACC Decision No. 66028 of 18 December 2002. I was an Intervenor and Party.

d. Docket No. E-04230-03-0933[4], the UniSource-Sahuaro Acquisition hearings.

e. Reopened and ongoing Docket No. E-01032A-99-0401, the Santa Cruz County service quality, analysis of transmission and proposed Plan of Action case, and

f. Reopened Arizona Power Plant and Transmission Line Siting Case No. 111,[5] and which may reconvene depending upon the resolution of the E-01032A-99-0401 Docket.[6]

g. Open Docket Nos. G-04204A-06-0463, G-04204A-06-0013, and G-04204A-05-0831, the ongoing UNS Gas, Inc., Rate, PGA, and Prudency Cases as a party and intervenor.[7]

h. Open Docket No. E-04204A-06-0783, for this proceeding as a party and intervenor.

Q. Have you received advise or help from others in preparing you Testimony?

A. All filings and testimonies are totally mine, for no one else, and are at my own expense.

Q. Why did you feel a need to intervene in these proceedings?

A. When I first read the Application and associated Direct Testimonies, many issues of concern became apparent. As stated in the Magruder Motion to Intervene[8] these included the following which were used as initial issues of concern that impact ratepayers prior to completing this direct testimony.

a. Proposed base rate increases since the 21% increase in August 2003,

b. *Mandatory* Time of Use (TOU) tariffs for new residential and small commercial ratepayers including implementation policies for automated metering,

c. Modified *rate structure* including a proposed overall rate of return of 9.89%.

d. Proposed Purchase Power and Fuel Adjustment Clause (PPFAC) rate structure,

e. New purchase power, generation and transmission agreements impacts on ratepayers,

---

[3] This case was before the ACC "in the matter of the joint Application of Citizens Communications Company and UniSource Energy Corporation for the approval of the sale of certain electric utility and gas utility Certificates of Convenience and Necessity from Citizens Communications Company to UniSource Energy Corporation the approval of the financing for the transactions and other related matters." This case was combined with the Citizens PPFAC Case in ACC Decision No. 66028 filed on 18 December 2002. I was an Intervenor and Party.

[4] This case was before the ACC "in the matter of the reorganization of the UniSource Energy Corporation." I was an Intervenor and Party.

[5] This re-opened case is before the ACC. I am an Intervenor and Party in the reopened case.

[6] This re-opened case is before the ACC. I am an Intervenor and Party in the reopened case.

[7] There are three cased in this Dockets No. G-04204A-06-0463, "in the matter of the Application of UNS, Gas, Inc. for the establishment of just and reasonable rates and charges designed to realize a reasonable rate of return on the fair value of the properties on UNS gas, Inc., devoted to its operations throughout the State of Arizona" and No. G-04204A-06-0013, "in the matter of the Application of UNS Gas, Inc., to review and revise its Purchased Gas Adjustor," and No. G-04204A-05-0831, "in the matter of the inquiry into the prudence of the gas procurement practices of UNS Gas, Inc." This combined case is open, having completed evidentiary hearings and all briefs filed while it waits for the ALJ's Recommended Opinion and Order as the next event, probably in mid- to late-August 2007..

[8] Marshall Magruder Notice to Intervene in Docket No. E-4204A-06-0783 of 12 March 2007.

f. New generation resources in Nogales for proposed forecasted demand and future impacts, if any, on Reliability Must Run in Santa Cruz County,

g. Compliance with various ACC Orders including a City of Nogales Agreement impacts on *system reliability* in Santa Cruz County service area since the last rate case,

h. Proposed Demand Side Management (DSM) program including specified demand reduction performance measurement goals and plans for all rate categories,

i. Prudency of its existing DSM Program since the last rate case,

j. Conservation principles proposed for all rate payers including energy audits and provision of cost-effective energy efficient devices for low income ratepayers,

k. Effectiveness of the ACC *Environmental Portfolio Standard* since the last rate case,

l. Implementation of the *Renewable Energy Standard and Tariff* for all rate categories,

m. Proposed rate policies may blur a clear separation of "cost of service" and "cost of power" as the former is the primary profit mechanism for this distribution utility.

n. Potential for any Citizens-UniSource transition of ownership costs to be absorbed by the customers beyond those in the Settlement Agreement, and

o. Potential for UNS Electricity, Inc. ratepayers to pay multiple or imprudent charges to UniSource Energy and its subsidiaries including increases in O&M and G&A.

Many of these have been included herein; however, some have been delayed due to a recent data request response from UNSE. Some have not been addressed due to discovery issues but will later in these proceedings.

1.3 The Demand-Side Management snafu.

Q. Do you have some issues that may be in this proceeding or another docket?

A. Yes. The proposed Demand-Side Management Program is perplexing as some UNSE testimony requests that a DSM Adjustor to customers rates be determined in this case but the details of the actual proposed DSM Programs to be adjudicated in a separate case.[9]

The issue here is how can the Commission determine a "fair and reasonable" DSM Adjustor rate <u>before</u> the proposed DSM Programs have been reviewed for prudency,

---

9 There are several different DSM Program Portfolios or plans presently under consideration in this USNE Electric Rate case, in the UNSG Gas Rate case, and a proposal by UES for a separate case. The Direct Testimonies by UNSG were superseded by a Exhibit DAS-3 filed on 23 March 2007, and then superseded again by a 4 May 2007 "informational" filing, the last but not entered into the record for UNS Gas, Inc. The Direct Testimony in the ongoing UNS Electric, Inc. docket (this one) contents have been superseded by the content in a UES letter of 13 June 2007, which requested a separate hearing for the UNSE and UNSG DSM Program plans, however, the 13 June 2007 has not been entered into the record of this proceeding.

reasonableness and even if a proposed DSM Program will be approved or denied by the Commission? In fact, my following testimony will <u>not recommend</u> one of the proposed DSM Programs because it is ineffective, environmentally unsound and is aligned with the Company's public relations goals and therefore is not appropriate for ratepayers to finance.

UES also stated it has another DSM Program filed in ACC Docket No. E-04204A-06-0783, the ongoing UNS Gas rate case. Testimony shows these are not the "same" programs as UES states in its letter but there are two USNE DSM programs have some similar characteristics with different actions, funding profiles, and requirements.

1.4 Additional Issues.

Q. Have you included all the issues related to this case?

A. No, there are several important issues that are related to my Second Set of Data Requests submitted on 4 June 2007. Based on an email by a UNSE attorney on 13 June 2004, a delay in responding to 26 June 2007 was requested. In view of this Direct Testimony being due two days latter, my response indicated that sending what was available on 19 June 2007 would be acceptable and the remaining on 26 June 2007. UNSE responded to most of the Data Requests on 19 June 2007 with two Data Requests that additional information was being gathered. These two deferred responses were be not received by 27 June 2007. The deferred responses involved CARES and CARES-M.

Many of the UNSE Data Request responses were identical with the below response:

> **"UNS Electric objects to this data request, as it is unduly burdensome and outside the scope of this rate cast."**

Every data request (DR) with this response (and a few incomplete one) is discussed below as to its relevancy in this case. It also should be noted that the Data Request closely is aligned with the specific areas of my interest, listed above, from the Magruder Motion to Intervene, which had no objectives by the USNE.

a. MM DR 2.5 requested status and cost information about present and future service extensions into Mexico.

(1) Requested the status and financial information about an existing customers residing in Mexico who purchase power for UNSE

(2) Requested the status of the ongoing 345 kV transmission line and its costs to date for each UniSource entity, e.g., how much of the $7 million or so spent to date will be allocated to UNSE ratepayers, TEP ratepayers, and/or shareholders and if these expenses are included in this rate case, when is this line going to be completed as it is long past its 31 December 2003 in-service date, if UNS intends to "write off" any of these expenses, correspondence received that shows the DOE Presidential permit has passed its DOE international reliability review for its cross-border operations,

and status of WECC and Mexican approvals on this line including relevant correspondence.

b. MM DR 2.6, requested cost of compliance with a Settlement Agreement with the City of Nogales, in particular, several actions that may not be in compliance of the Agreement approved by the Commission in ACC Decision No. 61793.

(1) Cost to comply with and status of the mandated Santa Cruz County economic-development efforts including how "new-business incentive tariffs" are being implemented in this Rate Case.
(2) Cost to fund and status of the ACC-mandated four-year annual scholarship/loan, which appears not to have been awarded for at least the past three years. **This is one of the largest scholarships in this county, provides the Company with an excellent way to improve its image in this community, and a way to have college graduates return to our community.** My quest for compliance with this agreement will continue until UNSE complies or if compliance is not demanded by the Commission.
(3) Cost to fund and the status of the mandated community relations efforts, in particular, the Citizens Advisory Council (CAC), which has one of its duties to discuss Demand-Side Management planning for the community.

c. MM DR 2.7 requested information about franchise agreements with cities and towns to determine if a fair balance exists between the cities/towns and the Company.

(1) Status of all franchise agreements such as renewal dates.
(2) The Franchise Tax associated with each agreement.
(3) Total Franchise Tax collected by incorporated entity
(4) Status of contentious issues between the Company and these entities (note, Nogales cancelled its agreement in 1999 but voted in September 2003, with 56% approving a new Franchise Agreement with UNSE.)
(5) Status of new franchise agreements being considered.

d. MM DR 2.8 requested the status of compliance with various ACC orders, noted in the Company's Testimonies, in which compliance is required by report submission to the ACC or other means.

(1) Cost to comply with these various orders that impact UNSE rates or capital improvements
(2) Annual costs since 2003 to determine trends, ways to consolidate reports to the ACC, or other means to reduce such reports and avoid unnecessary Company expenses.

e. MM DR 2.9 requested information about a new 46 kV transmission line between Pima and Santa Cruz Counties and rights of way purchase and lease costs for 46 kV and larger transmission lines on <u>public</u> lands

(1) Annual lease or rental cost for various public domain rights of way.
(2) Estimated costs for public rights of way costs for future expansions listed in the Ten Year Transmission Plan.
(3) Changes in the existing UNSE Ten-Year Transmission Plan.

NOTE: previously, I had requested the UNSE Ten-Year Transmission Plan and USNE responded it was available at the ACC website. No UNSE Transmission Plans are posted.

f. MM DR 2.10 which is very similar to DR 2.9, but for private lands expenses only to date, and there are no references to known expansions.

g. MM DR 2.17 requested cost, status and performance information for the existing UNSE generation plant at the Valencia Substation.

(1) Determination of the generation capabilities of this generation plant, as the Beck Testimony used values different from known nameplate data.
(2) Blackstart capability as this significantly impacts restoration of power and cost of other reliability improvements.
(3) Determination of emergency load limits in this docket as additional capabilities are present to handle peak loads without additional equipment in this rate case thus a saving to the Company and ratepayers.
(4) Cost of reactive capabilities, as Mr. Beck testified an additional 25 MVARS were recently installed to improve reliability.
(5) Status of meeting NERC/WECC reliability criteria for the four generators. If not, how much will it cost to meet reliability standards?

h. MM DR 2.18 requested information about the status, capabilities and requirements to improve the four substations in Santa Cruz County. In this service area, the distribution system has been the prime cause of customer outages and significant upgrades to these four substations were recommended in earlier hearings. Without technical information, the determination of cost-effective alternatives becomes more challenging.

(1) Technical status of the transformation of transmission to distribution power so as to assess if major upgrades are required or can other means can be used to expand the substations capabilities using more efficient and less expensive systems.
(2) Status of the substations SCADA systems to assess if the substations can handle possible DSM requirements.
(3) Pre-set equipment settings to respond to power outages with faster restoration times, as some systems switch to a backup source in a few cycles, in much less than one second, or a light blink even with a major category N-2 or N-3 outages.

i. MM DR 2.19, indicated that UNSE's response to MM DR 1.9b that designated a website with UNSE Ten-Year and RMR studies. This DR stated these documents are not posted at that site.

(1) Copies of these key reliability documents were requested for a second time along with working papers of supporting data.
(2) There was no objection to the first request DR 1.9b that referred me to a website.

j. MM DR 2.20, requested a summary of the current Purchase Power Agreement with PWCC, since an earlier DR 1.9c, it was denied as being "confidential."

(1) In other proceedings, this document was provided in public filings and was NOT confidential, therefore classification should not be an issue.
(2) In this Data Request, due to UNSE's sensitivity on this issue, only a summary of changes was requested as a second attempt to determine the financial relationships that exist with the single electricity source for UNSE.

k. MM DR 2.21 requested information about the costs for "blue stake" corrective actions. This was not understood in a prior DR 1.11b. The aim of these "blue stake" questions are to determine if the trends are up or down, implying that more funding might be needed for blue stake operations, especially due to new construction activities in both Counties.

(1) Cost to repair cut lines that were and were not "blue staked" was requested
(2) Cost of the five most expensive repair events with descriptions to assess if ways to avoid these could be recommended.
(3) Lessons learned from blue stake operations that could make this program more successful. Not asked but in the background, if resultant recommendations should be funded.
(4) Annual costs of blue stake operations, to determine trend and changes.

l. MM DR 2.25 requested copies of reports listed on Bates (0783)05428 and include

(1) ACC Ten Year Facilities Construction Plan
(2) ACC Environmental Portfolio Surcharge Reports
(3) ACC Integrated Resource Plan Annual Report
(4) ACC Annual Meter Testing Reports
(5) ACC Service Interruptions Annual Reports
(6) ACC Monthly PGA Report (only for test year)
(7) ACC Environmental Portfolio Information Semiannual Reports

m. MM DR 2.29, based on UNSE responses to STF DR 3.2 that stated the backup testimony for two persons (Mr. Ferry and Mr. Beck) will be provided in a supplemental response.

(1) The UNSE Supplemental Response to STF DR 32. on 10 and 17 May did not include any backup for Mr. Beck's testimony.
(2) The response to MM DR 2.29 said there is no backup for Mr. Beck's testimony.

n. MM DR 2.30 requested information about the Valencia Substation and the new 100-year flood plain which has this only substation in Nogales underwater.

(1) Status of additional upgrades to Valencia when a second substation (gateway) was recommended as both a second substation with backup capabilities, to improve local reliability
(2) Status of potential requirements by the County Flood Director requiring a 500-year flood plain requirement for the ONLY substation that services about 50% of the UNSE customers and provides the generation facilities used during natural causes to lose power.
(3) Cost and tatus of the contamination cleanup at the Valencia Substation noted in USNE response STF DR 3.86.

Responses to the above Data Requests and another being prepared may result in additional issues be resolved in this rate case.

PART II

ISSUES IN THIS TESTIMONY

The following are the primary issues and areas of concern presented in this Testimony

1. Demand Side Management Programs in Part III
2. Administrative Rules and Regulations Changes, Billing Schedules, Predatory Loan/Check Cashing Facilities as Billing Agents, Revised Billing Statement, and R&R Publication in Part IV
3. Cost to Improve Electricity Reliability in Santa Cruz County in Part V, incomplete, see 12 July 2007 Testimony.
4. CARES and CARES-M Tariffs in Part VI, incomplete, see 12 July 2007 Testimony

The first issue is provided with supporting testimony to support the conclusions and recommendations for all seven proposed DSM programs, one of which was NOT recommended. This testimony is in Part III.

The second issues are identical to the same issues form the UNS Gas, Inc., in ACC Docket No. G-04204A-06-0013, et al, with recent testimonial hearings and briefs submitted to the Administrative Law Judge on 20 June 2007, for review and consideration prior to issuance of the Recommended Opinion and Order (ROO) anticipated about mid to late August 2007. To reduce extensive dialog on these two issues, a discussion on each is included in Part IV below while the Magruder Reply Brief on these issues is provided as Exhibit B.

The third issue, involving the ongoing cost of improved reliability in the Santa Cruz service area, was discussed earlier in 1.4 and testimony will be in Part VI below. Completion of testimony on this issue awaits responses to data requests.

The fourth issue, involving administration and cost containment of the CARES-M tariff testimony is in Part VII below. A significant data request on this issue was to have been received by 26 June 2007. It has not been received by 27 June 2007, thus requiring this issue to await the results of this deferred data request.

PART III – ISSUE

DEMAND-SIDE MANAGEMENT PROGRAMS

3.1 UNS Electricity Demand-Side Management Programs.

On 13 June 2007, UniSource Energy Services (UES), for UNS Electricity, Inc., filed with the ACC Docket Control a letter that requested the Commission to

(1) Establish a docket for consideration and approval of seven proposed DSM Programs;

(2) Issue a Procedural Order establishing a hearing schedule in the docket; and

(3) Order a Procedural Conference to discuss testimony and exhibits in the docket; and

(4) Approve the proposed DSM Programs, contingent upon establishment of a DSM Adjustor to recover costs.[10]

This UES letter also added three new DSM programs and enhanced the DLC program that are not included the Applicant's Direct Testimonies.[11]

The proposed UNS Electricity Demand Side Management Program portfolio consists of seven programs:

a. Education and Outreach Program
b. Direct Load Control Program
c. Low-Income Weatherization Program
d. Residential New Construction Program
e. Residential HVAC Retrofit Program
f. Shade Tree Program
g. Commercial Facilities Efficiency Program

Each program is independent of others and of similar programs proposed by UNS Gas, Inc. as no synergy between UNSE and UNSG has been proposed, to date. The Education and Outreach Program provides all the external media exposures, training, and marketing support for all UNSE DSM Programs.

3.1.1 Basic Types and Definitions of Demand-Side Management Programs.

There are three basic types of DSM Programs,[12] which include

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10 UNSE letter "Re: UNS Electric, Inc.'s Demand Side Management Program Portfolio Filing, E-04204A-07-_____", hereafter "UNSE DSM Plan (13 June 2007)", at 2.

11 *Ibid.* at 1.

12 This testimony uses the below three definitions that compose of demand-side management (DSM) where DMS itself is defined as "The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use." From the Western Electricity Coordinating Council Glossary at http://www.wecc.biz/wrap.php?glossary/index.php

a. **Energy Conservation (EC)**, where the ratepayer/customer voluntarily reduces electrical demand by an action, such as lowering the thermostat setting on a hot day or turning off appliances when not being used.

b. **Energy Efficiency (EE)**, where equipment or other devices automatically go to settings or a mode of operation to reduce the electrical demand, such as an automated thermostat that used customer/ratepayer's preset time of day changes or when incandescent lights have been replaced by fluorescent or light emitting diode (LED) lights, which use less power, or sets the swimming pool pump to operate from midnight to 0400, when demand is very low.

c. **Demand Reduction (DR)**, where equipment or devices, upon signal to lower electrical demand, reduces the load of that customer, for example, when the utility uses remote control to adjust the thermostat to a higher temperature setting to turn off an air conditioner, or remotely controls one's refrigerator, electric hot water heater, or swimming pool pump.

The seven proposed UNSE DSM programs are of the type(s) shown in Table 1.

Table 1 – Types of Demand-Side Management for the Seven Proposed UNSE DSM Programs.

Type of DSM / UNSE DSM Program	Energy Conservation (EC)	Energy Efficiency (EE)	Demand Reduction (DR)
1. Education and Outreach	Yes	Not as proposed	No
2. Direct Load Control	No	No	Yes
3. Low-Income Weatherization	No	Yes	No
4. Residential New Construction	No	Yes	No
5. Residential HVAC Retrofit Program	No	Yes	No
6. Shade Tree Program	Yes	No	No
7. Commercial Facilities Efficiency	No	Yes	No

In paragraphs 3.2 to 3.2, each of these programs is discussed in terms of proposed scope, references, requirements, verification, and recommended improvements.

The 13 June 2007 UES filing, in general, follows the process outlined in a draft ACC DSM Study which includes ACC Staff Proposed DSM Rules.[13]

3.2 Education and Outreach DSM Program (EC with potential EE).

a. Scope. This program is designed to educate customers and provides an out reach opportunity for UNSE to prove its energy expertise by helping its customers solve today's energy problems

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These three types of DSM programs do not agree with those in the ACC Staff's Draft DSM Report, Exhibit 1, Proposed DSM Rules at 2. This report states DSM include energy efficiency, load management, and demand response and does NOT include Energy Conservation as a DSM Program. Further, it includes customer voluntary actions as a component of demand response which usually is an EC measure. Further, the definitions above for EC, EE, and DR have clearer boundaries.

[13] ACC Staff Proposed DSM Rules, Exhibit 1, Draft Demand-Side Rules, Rule R14-2-1705 for the process to implement a new DSM program including the requirement of each program proposal. Even in its draft form, this is good guidance; however, some enhancement elements have been included in this Testimony. This unofficial and draft process appears to be what UNSE is using at its guidance.

before they reach crisis levels. The objective of this program is to educate the public at all levels about electricity so they can wisely conserve, make wise energy efficiency choices, and understand how demand response programs benefit both ratepayers and the utility.

b. References. (1) UNSE DSM Programs (13Jun07) Attachment 1[14], (2) UNSE "Energy Advisor" website, and (3) Insulation Station Learning Kit

c. Program Requirements. This proposed program includes residential, academic, commercial and Time-of-Use educational programs. Each is targeted for different customers with the annual total being 79,000 residential customers, 10,000 future customers (students), 11,000 commercial customers, and an unknown number of TOU customers, respectively. Tools proposed to be used for these four programs include "Energy Advisor", media campaigns, learning kits for K-12 school children, school "Energy Patrol" conservation monitors, as telephone energy assistance. All the proposed implementation tools are passive with a much lower impact than active methods. All UNSE DSM Programs will be emphasized by all forms of media to reach the public.

d. Program Performance Measurement. Few are proposed; however, many objective measures are possible and recommended below.

e. Conclusion. At present a weak passive program without feedback, therefore little justification for the proposed funding was presented. Adoption of recommendations could justify level of funding being requested. Emphasis on existing EE and DR programs by this program can improve overall success. The ACC Staff's definition of types of Demand-Side Management Programs[15] does not include EC programs, thus without change, this program might NOT be included as a DSM program

f. Recommendations. The following are recommended that

(1) Add active implementation tools be including:

(a) Institute a policy for 100 feedback telephone calls within 3 days after a DSM bill insert mailing to determine receipt, understood and action taken as a performance measure.

(b) Provide an active speaker program for ALL local civic and business organizations. Monthly, the *Nogales International* provides well over 50 such organizations where Education programs are applicable with Consumer education for organizations such as Garden Clubs or Rotary clubs; Commercial education for Chambers of Commerce. EACH such organization should have a presentation annually, be provided handouts (such as the light bulb one below) with an annual goal of 2,500 attendees as a performance measure.

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[14] *Ibid.*, Attachment 1 – Education and Outreach Program, at 1-12.

[15] ACC Staff's "First Draft of Proposed DSM Rules, R-14-2-1702, Definitions at 2.

(c) Provide return in your billing envelop billing inserts to include "I want more information about ___," please have an Energy Advisor call, light bulb information (below), and even some simple contests ($50 Saving Bond awards), sign up for the UNSE Energy eNewsletter, etc.

(2) Develop into an Energy Efficiency (EE) program by having results monitored, assessed, and customers actions recognized. For example, a bill stuffer could be stress changing light bulbs with a coupon attached so one could mail in UPCs and store receipts for purchasing fluorescent light bulbs for a 50 cent rebate as reduction in next month's bill up to six per month ($3.00). (with several performance measures)

(3) Create an Energy eNewsletter (at least bi-weekly) where frequent EC and EE news is provided to customers including the latest federal EE and Arizona tax credits, impact of using your swimming pool pump on your TOU bills, and other ways to have UNSE become your "expert" on EC and EE matters including feedback from ongoing DSM programs. Measure number of eNewsletter subscribers.

(4) Expand "Telephone Energy Assistance" to **ALL** ratepayers; not just commercial customers, as all should be able to "ask an energy question and receive an answer."

(5) Include building contractors and developers in the Commercial educational programs to cover comprehensive building EE requirements with introductions to other UNSE DSM programs. Better would be develop a series of presentations leading to a qualification, with a "UNSE Building Energy Efficiency Graduate" as a diploma has *de minimus* cost but high psychological benefits. Establish a minimum goal of 50 or graduates per year.

(6) Aggressively pursue achieving and surpassing performance measures.

(a) Number of light bulb rebates after a flyer mailing (from telephone interviews) or presentation noting percent and trends.

(b) Number of individuals and school children who attended a UNSE energy presentation.

(c) Increase the number of grades and "learning kits" used in the academic program, such as a "basic electricity and safety" in the 8^{th} grade (at least 3 lessons) and "understanding your electricity bill" in the 12^{th} grade (at least 3 lessons).

(d) Increase in use of Energy Advisor after a directed media campaign to determine the media campaign effectiveness such as number of hits per page per month to determine which pages (information) are of interest. Use Energy Advisor to collect information, and then analyze to determine customer's interests, which should be used for focus media campaigns.

(e) Results of short oral or written quizzes after the 4^{th} Grade classes to determine understanding and percent who complete all the "fill-ins" in their notebooks.

(f) During civic or business presentations, requests for number of "hands" who know about "Energy Advisor" and "how many have used Energy Advisor." Ask for their feedback, same questions, record numbers, note trends and percentages.

(7) Ensure Energy Advisor is capable of displaying all Time-of-Use (TOU) information, specifically tailored to that customer's account using that customer's current and at least the prior two years bills with calculators necessary to make a TOU decision. Without personal account information, the customer is blind. Further, for customers on TOU, they should be able to determine their fifteen-minute demand loads for the prior twelve months, as a minimum. This is required to understand when (day/time of day) their peak, shoulder, and off-peak demand occur in order to reduce their electric load. Specifically, their high 15-minute demands (Peak, Off-Peak, Shoulder) are used to calculate their entire monthly bill. Further, this should be very easy for customers to understand.

(8) Ensure Energy Advisor can show a customer's account data for assessing changing to "levelized" payment plan.

(9) Place an English/Spanish language toggle on the Energy Advisor home page.

(10) Change the ACC Staff's Draft DSM Report definitions for types of DSM Programs to agree with those herein, because, as presently worded, the Education and Outreach Program is not a DSM program.

(11) Determine the annual costs of this program, and then divide by the total of a weighted number of monthly customers, so this program's DSM Adjustor can be calculated.

Table 2 – Summary of Proposed Educational and Outreach Programs.

Programs / Tools	Residential	Academic	Commercial	Time-of-Use (TOU)
Energy Advisor	(1) Home Energy Analysis (2) Energy Saving Calculator	Yes	Business Energy Advisor with case studies	It is expected (but not stated) that customer's TOU benefits are included.
Consumer Education	Media campaign (bill inserts, radio ads, homepage icons)	NA	Media campaign (bill inserts, radio ads, homepage icons)	Media campaign (bill inserts, radio ads, homepage icons), door tags, brochure
Insulation Station learning kit	NA	4th Grade	NA	NA
Energy Patrol conservation monitors	NA	K-12th Grade	NA	NA
Telephone Energy Assistance	Not proposed; however, recommend inclusion	Yes	Yes (LPS customers are assigned account managers)	Customer Service Reps to provide TOU information

3.3 Direct Load Control (DLC) DSM Program (DR).

a. Scope. This demand reduction program is designed for UNSE to reduce customer critical demand for reliability or for economic reasons. As presented, this is a weak program. The objective of the DLC program is to provide a mechanism for UNSE to reduce electricity demand. UNSE will publicize this program under the Education and Outreach program (see 3.2) The benefits of this program are [16]

(1) An annual on peak demand reduction of 9,400 kW[17] which is equivalent to $6.58 million (9,400x700) in capital cost savings by the Company for peaker gas turbines, using $700/kW[18] or significantly higher if coal or nuclear power plants were required to meet this additional peak load.

(2) A total annual reduction of 318,000 kWh cumulative demand during the Peak TOU hours (averaged) or 90.9 kWh (318,000/3,500) per participant, equivalent annual savings of about $9.00 savings per resident in lower electric bills.[19]

(3) The TOTAL reduction of green house gas (GHG), other air pollutants and saved water from 2008 to 2012 is estimated to be:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved or not generated
CO_2	2,331,794	SO_2	1,119	Water	XXX gallons
NO_x	3,614	Ozone	XXX	Mercury	XXX oz

(4) At an annual implementation cost (DSM Adjustment) of $XXX.XX ($1,968,000/XXXXX) per new participant in 2008 reducing to $XXX.XX ($1,537,637/XXXXX) in 2012.[20]

(5) At a month DSM Adjustor surcharge of $XX.XX per kWh per residential customer for this program, or on an average bill of $X.XX for monthly usage of XXXX kWh.

(6) This program has a society test benefit effectiveness ratio of 1.21.[21]

b. Reference. UNSE DSM Programs (13 June 07), Attachment 2[22]

c. Program Requirements. This proposed program includes installation of DLC on about 35,000 residential central air conditioning and small to mid-sized commercial systems within the next ten years, averaging 3,500 installations per year with 95% expected to be residential and 5%

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16 Based on the recommendations below, the existing benefits will change, thus it is recommended that all the XXX's in this subparagraph be completed in the applicant's Rebuttal.

17 UNSE DSM Programs (13 June 2007), Attachment 2, Table 4 at 8.

18 Direct Testimony of Edmond A. Beck on Behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Beck Direct Testimony" at 6 and 11 which state that a 20,000 kW LM-2500 gas turbine was installed in Nogales for approximately $14 million, or for $700/kW (14,000,000/20,000)

19 *Ibid.*

20 *Ibid,* Attachment 2, Table 2 at 7.

21 *Ibid,* Attachment 2, Table 6 at 8.

22 *Ibid.,* Attachment 2 – Direct Load Control Program at 1 to 16.

commercial systems. UNSE will establish the communications protocols, install software and determine vendor services to implement DLC. UNSE will formally establish a baseline so additional DR programs can be added and conduct analyses of process, operations, customer satisfaction, and program energy impact to determine program success. UNSE will either internally accomplish or contract-out the DLC program. UNSE has not conducted a pilot DLC program.

Based on

> "favorable geographic, demographic and market characteristics, this DLC Program will only be available to customers located in the Lake Havasu area. UNS Electric will <u>not</u> offer the DLC Program to schools, retirement homes, hospitals or to other customers who have the need for stringent temperature and/or humidity control. UNS Electric has no requirements that customers meeting the above are also required to utilize a TOU rate, but TOU customers are not precluded from participation in the DLC program.[23] [emphasis added]

The UNSE DLC Program will use an on/off "50% cycle for each customer during the control event."[24] UNSE also states:

> "UNS Electric intends to reserve control periods to those hours when the cost of purchase power on the wholesale market meets or exceeds $115/MWh (this is to remain within a limit of 100 hours per year). Customer selection is part of the information technology set-up protocol. Depending on the MW reduction needed during each control event, a specific group of customers from the top of the list is selected for control. If the control event lasts longer than the maximum of four-hour time period, the first set of customers return to normal generation and a new set of customers replace them for the duration of the event. Once a customer has been interrupted once, they move to the bottom of the list and will not be controlled again until their name moves to the top of the list again."[25]

d. Program Performance Measurement. The proposed 50% cycling appears to be too high (see conclusion (2) below) and average impact per thermostat (or installation) too low when other readily available electrical equipment can be easily added to the DLC system at minor expense with high energy reduction readily available. Thus, the estimated energy savings needs to be redone. Further, the new installation costs need to be broken down into labor plus specific equipment (thermostat at $150/installation, $XX two-way communications pager, $XX appliance and pool pump controls, etc.) with higher anticipated customer and UNSE savings included in the forthcoming UNSE Rebuttal.

e. Conclusions.

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[23] UNSE Response to Magruder Data Request MM DR 2.13.c; UNSE DSM Program (13 June 2007) at 2 states that of the 79,000 UNSE residential customers at 11,000 commercial customers, approximately 31,000 residential customers and 4,000 small commercial establishments are in the Lake Havasu area.

[24] UNSE Response to Magruder Data Request MM DR 2-13.c

[25] UNSE Response to Magruder Data Request MM DR 2.13.d

(1) A correct description of the proposed UNSE DSM Program must be in the UNSE Testimony, as Mr. Ferry's is erroneous and should be stricken or replaced in Rebuttal.

(2) A 50% cycle time (OFF for up to 2 hours in a four-hour cycle) in one of the hottest locations in the county is a cycle time that maybe hazardous to those whose air conditioners are required for nearly 100% of the time. A review of a successful Florida Power and Light DLC program has a 15-minute OFF cycle not more than once every four hours. This would be satisfactory since Florida is also a hot weather area. This will greatly reduce the "benefit" computations by about 87.5% (2 consecutive hours OFF per four hours to 0.25 hours OFF per four hours).

(3) Air conditioners are the only equipment included in the proposed UNSE DLC program. Other companies have also used DLC for other high electricity demand equipments, to greatly improve the efficiency and benefits of DR and are an especially appropriate option for TOU customers who want to reduce their demand and electricity bills. These include

   (a) Swimming pool pumps to OFF for entire peak/shoulder TOU periods,

   (b) Electric hot water heaters to OFF during entire peak TOU periods,

   (c) Electric dish washing, clothes dryers and washing machines,[26] to OFF during peak TOU periods, and/or

   (d) Refrigerators and Freezers for 15-minute cycles same as air conditioning. Both of these appliances generate interior heat, therefore it is better for the air conditioner to not be running whenever air conditioning is cycled to OFF.

(4) Since UNSE has not been involved in a DLC program of this magnitude, nor has TEP, then use of commercial off-the-shelf (COTS), proven, DLC hardware and DLC software that use common, industry-standard protocols and standards, is the only way to install this kind of system. NO unique, proprietary software or hardware should be considered under any circumstance for this program as future interoperability and expansion depend on open system architectures, as "closed" systems are always losers after their first few years of operations, as equipment sources dry up, software protocols change, and unless completely open, future expansion options are closed early and your system becomes rapidly obsolete, requires extensive maintenance and replacement, long before the its life cycle requires. Hire the best consultants, but beware of any "exclusive" or "trust me" promises. Proven systems, by definition, work. Unproved ones don't.

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[26] In Arizona, during the summer peak TOU periods, hot water heaters could be between 100F and 120F or higher with ambient air temperatures but dish and clothes washing may require higher temperatures on hot cycles, thus, whenever a DLC cycle turns OFF an electric hot water heater, both electric cloths washing and dishwashing machines should be synchronized temporally with its electric hot water heater.

(5) NO incentive is provided for customers to use DLC, except to reduce load during peak or shoulder TOU periods. A free thermostat is a 'given' and not enough to be worth enrolling in the DLC program; however computation of the total energy savings for air conditioners, electric water heating, dish and clothes washing machines, and clothes dryers; swimming pool pumps, maybe be enough to persuade some but it would seem not enough to make DLC successful.

Financial incentives are usually given for DLC programs, either in the form of a flat rate reduction or a calculated "bonus" due to lower electricity consumption that is applied to one's rate. I received a 13% rate reduction for a voluntary DR program (really EC) to avoid use the above equipment during peak demand periods with no oversight or detailed legal agreements with the utility.

Better than a "flat" reduction would be a calculated "saver bonus" based on actual, measured savings printed on one's bill. This could compare last year to this year, last month to this month, account for weather differences, and actual "demand you reduced" during the prior month. Such a "bonus' could only be awarded when significant "benefits" occur with lower purchase price for electricity and avoided infrastructure costs to the utility. In one case, FPL avoided about $3 billion with a DR program for A/C, electric water heaters, pool pumps, and clothes dryers installed and paid by FPL (not ratepayer) company expense. FPL gave a flat rate reduction of $13 per month.

f. Recommendations. It is recommended that:

(1) CARES-M customers, required to have electric-powered life-support equipment, be excluded from participating in a DLC program unless on-site determination can be reviewed by UNSE and the equipment DLC cycling scheme approved in writing by the attending physician.

(2) Mr. Ferry's Direct Testimony on the proposed UNSE DSM programs in this docket is erroneous, misleading and divergent from the 13 June 2007 UES filing. Mr. Ferry's Testimony on proposed USNE DSM programs[27] must be stricken and from the 13 June 2007 filing inserted in to the record for these proceeding.

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[27] Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Ferry Direct Testimony", at 14 (starting at B. Proposed DSM Programs) to 22 (ending at VII. Rules and Regulations. Some of the gross errors include different program names, he would not make DLC programs available to "preschool and senior care facilities" while all schools, retirement homes, hospitals, and other" are included in the 13 June version. In general, these pages in his testimony *en Toto*, have to be replaced in this application prior to consideration for approval. In addition, if only Lake Havasu area is to be considered until 2012, then many changes are also required in the 13 June 2007 plan to indicate this limitation.

(3) Reduce the 50% cycle time from two hours per four-hour cycle to 15-minutes per four-hour cycle, and to read "12.5% percent OFF cycle, not exceeding 15-minutes, per four-hour cycle."

(4) Add more Demand Response options for customers, including the following equipment options:

(a) All swimming pool pumps OFF during all Peak and Shoulder TOU periods, unless solar water heater installed, then a small recirculation pump is permitted to be bypassed but not the regular pool pump used to power pool cleaning equipment.

(b) All electric hot water heaters OFF during Peak TOU periods.

(c) All electric dish washing, clothes dryers and washing machines OFF during all Peak TOU periods.

(d) All electric refrigerators and freezers on the same 15-minute cycle schedule as proposed by UNSE for air conditioners.

(e) Other electric equipment that has high demand loads, such a sump or water well pumps that the customer wants added to the DLC Program as a way to reduce Peak and Shoulder loads, thus reduce that customer's TOU electric bill. In particular, small commercial ratepayers might want to cycle high energy cost systems OFF during Peak TOU periods.

(f) Revise proposed DLC Participation Agreement and program costs[28] In particular, try to reduce the length of the Participation Agreement by reducing redundant, superfluous words by using customer-oriented "plain" English at the ninth grade reading level

(5) Based on 3 and 4 above, recalculate Estimated Energy Savings[29] so program "benefits" can be determined. These additional equipment loads will increase Company and ratepayer savings.

(6) Determine and institute some kind of financial incentive for the ratepayers, with a "bonus" approach being considered superior to a flat rate rebate.

(7) Change to DLC Participant Agreement to include making telephonic changes to this agreement to match the program description.[30]

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[28] UNSE DSM Programs (13 June 2007), Attachment 2 at 7-8, Appendix 1 at 9-12; Appendix 3 at 14-15, Appendix 4 at 16.

[29] *Ibid.*, Attachment 2, at 7-8.

[30] UNSE DSM Programs (13 June 200&, Attachment 2 at 5 states "Participant will have the right at any time to over-ride a specific control event by notifying UNSE in writing or by telephone. Participant will have the right at any time after the first year to terminate the service by notifying UNSE in writing or by telephone." [note, "in writing" during a four-hour control event is not realistic.]. This statement is not reflected in Appendix 1 (DLC Participant Agreement) and contradicts paragraphs 9 and 21.

(8) Only Off-the shelf, proven, already developed DLC hardware and software using commercial, open systems architecture, industry standard IT protocols, without any proprietary software be purchased and integrated for the DLC program with none developed from scratch by any UniSource entity.

(9) Determine the annual costs of this program, then divide by the total of a weighted number of monthly customers, so this program's DSM Adjustor can be calculated.

3.4 Low-Income Weatherization (LIW) DSM Program (EE).

a. **Scope.** This DSM program is designed to assist lower-income customer's abilities to pay their utility bills by improving the energy efficiency of their residence to lower their consumption and thus monthly UNSE and UNSG bills. The objective of the LIW is to modify, add, or change the residence to lower consumption. The utility costs of this low-income customer program will be borne by all customer classes.[31] UNSE will publicize this program under the Education and Outreach program (see 3.2)

The benefits of this program are:

(1) An annual on peak demand reduction of 0.371 kW and 70 therms of natural gas[32].

(2) A total annual reduction of 1,091.7 kWh which will save $150.69 per LIW ratepayer per year and 70 terms of natural gas which saved a total $97.97 in gas bills.[33]

(3) The TOTAL reduction of green house gas (GHG), other air pollutants and saved water from 2008 to 2012 is estimated to be:[34]

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved
CO2	377,602	SO2	181	Water Saved	XXX gallons
NOx	585	Ozone	XXX	Mercury	XXX oz

(4) At an annual implementation cost of up to $2,000.00 per participant.

(5) At a month DSM Adjustor surcharge of $XX.XX per kWh per residential customer for this program, or on an average bill of $XXX,XX

(6) This program has a society test benefit effectiveness ratio of 0.453.[35]

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31 ACC Staff's First Draft of Proposed DSM Rules, Exhibit 1, Draft Demand-Side Management Rules, Rule R14-2-1706.D at page 6.

32 UNSE DSM Programs (13 June 2007), Attachment 3 "Low-Income Weatherization Program, Table 4 at 6. The annual peak demand used the noncoincident peak savings is 3 kW; however the data in Appendix 2 at 13 shown 0.371 kW as "Non. Coin. Demand Savings (kW)". This difference is not explained.

15 *Ibid.* Appendix 2 at 13. The total annual reduction (saved electricity) totaled the winter and summer kWh savings, the savings per ratepayer multiplied total annual reduction times cost ($0.9688/kWh) or $150.69. This table also shows customer cost savings at $203.79. This difference is not explained. The Therms savings is from this page and multiplied by cost/Therm of $1.40 equaled natural gas savings.

34 *Ibid.* The Company's Rebuttal will need to complete the rest of this table shown by "XXX"

b. Reference. UNSE DSM Programs (13 June 2007) Attachment 3.[36]

c. Program Requirements. Eligible low-income participants are referred to this program by community service agencies[37] who determine the customer's priority for LIW assistance. Initially, funding will be provided for 40 LIW participants in 2008 increasing to 45 in 2012 by UNSE while the community service agency implements the UNSE LIW program, along other federal and Arizona LIW programs, its local process, thus there will be variations throughout the UNSE service area.

UNSE will report the lost revenues to be recovered.[38]

d. Program Performance Measurement. This program includes a long list of items[39] that the community service agencies can include when it contracts for weatherization. The agencies will update tracking software and submit invoices to UNSE for reimbursement.[40] Using both the software inputs and invoices, UNSE can determine which EE devices, equipment, appliances or work tasks accomplished for its contribution to the service agency. These are then used to assess LIW performance. The LIW Program Costs shows many managerial, clerical, General and Administrative (G&A), labor, materials, labor activities (such as curriculum development, and customer education), facilities audits, rebate processing and inspection, CARE billing assistance, with a total budget of $106,000 for the LIW program.[41] It is also noted that the CARES rate discount is not a DSM Program; however, the recipients may be the same for LIW and CARES, including CARES-M.

The LIW Program "monitoring and evaluation plan" seems excessive. IF well-written contracts are implemented with each agency then installation data reporting can and should be embedded in such contracts, including on-line "forms" the contractor fills to enter directly into a database. UNSE monitors and provides feedback to the community service agency with voucher payment being dependent on correct, timely, and complete data reporting.

e. Conclusions.

(1) The Program Costs should include only the program charges necessary to accomplish the LIW program following from Appendix 1, therefore a summary of the LIW Costs is shown in the below Table 3.

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35 *Ibid.* Table 6 at 6.

36 UNSE DSM Programs (13 June 2007), Attachment 3 "Low-Income Weatherization Program: at 1-19.

37 Mohave County is serviced by the Western Arizona Council of Governments (WACOG) and Santa Cruz County by Southeastern Arizona Community Action Program (SEACAP).

38 UNSE DSM Programs (13 June 2007), Attachment 3 at 6.

39 USNE DSM Programs (13 June 2007), Attachment 3, at 14-18.

40 *Ibid.*, Appendix 3, Low-Income Weatherization Program Implementation Process at 19.

41 *Ibid.*, Appendix 1, Program Costs at 8-12.

Table 3 – LIW Program Budget with Proposed Change.

Budgeted Item	Budget	Comments
Administration Costs		
Managerial and Clerical Labor	$14,175	No change
Travel & Direct Expenses	0	No change
Overhead (G&A) Labor and Materials	$1,575	No change
Subcontracted Marketing Expenses	0	No change
Total Administrative Costs	$15,750	No change
Direct Implementation		
Financial Incentives to Customers	$79,947	No change
CARES Billing Assistance	**$2,552**	Delete CARES Billing Assistance
Total Evaluation, Measurement, Verification	$4,200	No change
TOTAL Implementation Cost	$84,147	Deleted $2,552 for CARES Billing
Total Budget	102,448	Deleted CARES Billing Assistance

(2) This program uses 82.1% (79,947/102,448) of its costs going directly to LIW participants; however, the Company should look for ways to reduce its administrative costs.

f. Recommendations. It is recommended that:

(1) Program environmental benefits include other parameters, such as potable water saved, pounds of Ozone, ounces of Mercury, and others which might be unique environmental contributions to society.

(2) CARES Billing Assistance $2,552 be deleted in the LIW Program Budget as CARES is a rate issue. All CARES and CARES-M costs are calculated in the rate structure.

(3) The benefits in terms of the proposed residential rates need to be recalculated.

(4) This programs DSM Adjustor be determined by dividing the number of monthly customers by the annual cost of this program

(5) It should be noted that "the Commission shall determine whether a utility may be allowed to recover lost net revenue." [42] This decision has not been made by the Commission.

3.5 Residential New Construction DSM Program a.k.a. Energy Smart Homes (ESH) (EE).

a. Scope. This program will provide Energy Smart Homes (ESH) to emphasis the whole-house approach to improving health, safety, comfort, durability and energy efficiency for homes that meet the EPA/DOE Energy Star Home® performance requirements. All UNSE homes are in IECC[43] region 3. Required on-site inspections and field testing will be conducted to ensure the

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[42] ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1 Draft Demand-Side Management Rules, R14-2-1709.B, which states "The Commission shall determine whether a utility may be allowed to recover lost net revenue." Also the utility expenses may decrease in this DSM program.

[43] International Energy Efficiency Code (IECC) of 2006 which is embedded in the International Building Code (IBC) that has been adopted by both Santa Cruz and Mohave Counties (Mohave's becomes effective 1 September 2007).

performance standards are achieved. UNSE will publicize this program under the Education and Outreach program (see 3.2)

The benefits of this program include [44]

(1) An annual peak demand reduction of 395 kW in 2008 and increases to 623 kW in 2012.[45]

(2) This peak reduction is equivalent of saving $276,500[46] (395x700) in capital costs for new "peaker" generation facilities which can save the Company future capital costs using $700/kW for a gas turbine, or much higher costs for coal or nuclear power plants in 2008 and $427,700 (611x700) in 2012.

(3) A total annual reduction of 470,111 kWh energy savings in reduced demand and 28,619 Therms in 2008, increasing to 726,430 kWh energy savings and a total 44,221 Therms in 2012.[47]

(4) The annual implementation cost of $1,042.18 per participant ($420,000 /403 homes) in 2008 decreasing to $686.59 per customer ($427,714/ 623) in 2012.[48] Only $400 of which is provided as a rebate, thus the cost/benefit ratio is 2.605 (1042/400) which is too high.

(5) The TOTAL reduction of green house gas (GHG), other air pollutants and saved water from 2008 to 2012 is estimated to be:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved
CO2	5,168,086	SO2	2,479	Water	XXX gallons
NOx	8,010	Ozone	XXX	Mercury	XXX oz

(6) At a month DSM Adjustor surcharge of $XX.XX per kWh per residential customer for this program, or on an average bill of $X.XX for monthly usage of XXXX kWh.

(7) This program has a society test benefit effectiveness ratio of 1.92.[49]

b. References. (1) UNSE DSM Programs (13Jun2007) Attachment 4; (2) DOE Energy Smart Home® website at www.energystar.gov ; (3) UNSE Website Energy Advisor.

c. Program Requirements. UNSE will establish the infrastructure necessary to promote, build and qualify Energy Star Homes® in its service area.

UNSE will report the lost revenues to be recovered.[50]

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44 Based on the recommendations below, the existing benefits will change, thus it is recommended that all the XXX's in this subparagraph be completed in the applicant's Rebuttal.

45 UNSE DSM Programs (13 June 2007), Attachment 4, Table 5 (not paginated).

46 *Ibid.*

47 *Ibid.*

48 *Ibid.* Cost per Participant use Total Budget Costs from Table 4, divided by number of projected participants in Table 5.

49 UNSE DSM Programs (13 June 2007), Attachment 4, Table 7, Benefit-cost analysis results (pages unnumbered)

d. **Program Performance Measurement**. UNSE will collect data, maintain a progress tracking database and provide periodic reporting. UNSE with its implementation contractor will establish an integrated data collection system, conduct field verification of sample installations, and track saving values to ensure goals are being achieved.[51]

e. **Conclusions**.

(1) This program has only 38.4% ($161,312/$420,000) of its 2008 total programs costs going direct to LIW participants. The Company should reduce its costs, especially recurring costs.

(2) The projected percent participation in this program is way too small at 9% in 2008 increasing to 10% in 2012. It is my understanding, 42% of all new homes being built in Nevada are DOE Energy Star Homes®. If 42% of all homes in 2012 were ESH homes or 2,560 homes instead of 623 homes, then, linearly extrapolating, then in 2012 could be:

- Peak Demand reduction increases from 265 kW to 2,593 kW
- Annual savings in Company's capital peaker plant cost of $276,500 increases to $2,705,550 in avoided peaker plant costs a year.
- Annual reduction of peak demand increased from 726,430 kWh to 7,108,800 kWh and 432,700 Therms were saved.
- The Total reduction of green house gas (GHG), other air pollutants and saved water between 2008 and 2012 would be estimated to be:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved
CO2	50,568,000	SO2	24,440	Water	XXX gallons
NOx	78,378	Ozone	XXX	Mercury	XXX oz

(3) A sample Partner Agreement and/or the Energy Star Partner Agreement[52] between UNSE and the builder should be written in "plain" English and in this section.

f. **Recommendations**. It is recommended that:

(1) The Company should reduce its high costs, especially recurring costs, and improve its return to customers to 45% in 2009, 50% in 2010, 55% in 2011, and 60% in 2012.[53]

(2) That annual goals increase from 9% in 2008 and increase annually to 42% or higher in 2012, with new data presented in the UNSE Rebuttal reflecting this change.

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50 UNSE DSM Programs (13 June 2007). It is noted that ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1 Draft Demand-Side Management Rules, R14-2-1709.B, which states "The Commission shall determine whether a utility may be allowed to recover lost net revenue." Also the utility expenses may decrease in this DSM program.

51 *Ibid.,* after Table 2 (pages unnumbered)

52 UNSE DSM Programs (13 June 2007), Attachment 4, Appendix 4 (pages unnumbered)

53 *Ibid.,* Table 6, 2008 to 2012 budget (pages unnumbered),

(3) Determine the annual costs of this program, then divide by the total of a weighted number of monthly customers, so this program's DSM Adjustor can be calculated.

3.6 Residential HVAC DSM Program (EE).

a. **Scope.** This program will promote quality installation practices and high-efficiency air conditioning equipment that meets or exceeds a 14 to 16 SEER ratings.[54] A financial incentive will be provided to the residential ratepayers. UNSE will publicize this program under the Education and Outreach program in 3.2 above. UNSE will monitor for "lost" revenues.

The benefits of this program include:

(1) The annual peak demand reduction is 235 kW in 2008 and increases to 265 kW in 2012.[55]

(2) This peak reduction is equivalent to a savings $164,500 (235x700) in capital costs for new "peaker" generation facilities saving the Company future capital costs using $700/kW for a gas turbine, or much higher costs for coal or nuclear power plants in 2008 and $185,500 (265x700) in 2012. [56]

(3) A total annual reduction of 622,268 kWh energy savings in reduced demand and XXX therms in 2008, increasing to 700,368 kWh energy savings and a total of XXXX Therms in 2012.[57]

(4) The annual implementation cost per air conditioning or heat pump system is $402.14 ($300,000/746 systems) for a total of 746 systems per year. Customer's incentives account for 57.6% of the program budget. [58]

(5) The total reduction of green house gas (GHG), other air pollutants and saved water between 2008 and 2012 is estimated to be:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved
CO_2	5,371,825	SO_2	2,577	Water	XXX gallons
NO_x	8,325	Ozone	XXX	Mercury	XXX oz

(6) At a month DSM Adjustor surcharge of $XX.XX per kWh per residential customer for this program, or on an average bill of $X.XX for monthly usage of XXXX kWh.

(7) This program has a society test benefit effectiveness ratio of 1.49.[59]

b. **Reference.** UNSE DSM Programs (13 June 2007) Attachment 5, "Residential HVAC Retrofit Programs"

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[54] UNSE DSM Programs (13 June 2007), Attachment 5, Residential HVAC Retrofit Program at 3.
[55] *Ibid.*, Table 5 at 7.
[56] *Ibid.*
[57] *Ibid.*
[58] *Ibid.* at 6.
[59] UNSE DSM Programs (13 June 2007), Attachment 5, Tables 3 and 4 at 6 and Appendix 2, Program Costs at 10 to 13.

c. **Program Requirements**. UNSE will use various media to reach residential customers UNSE employees will manage this program and provide overall management, marketing, planning, and customer coordination and contractor participation. UNSE will establish partnerships with HVAC training professions, contractors, and Arizona Energy Office. Both air conditioners and hear pumps will receive rebates at 14 SEER of $50/ton, 15 SEER at $75/ton, and 16 and above SEER 16 at $100/ton.

d. **Program Performance Measurement**. UNSE will collect data, maintain a progress tracking database and provide periodic reporting. UNSE with its implementation contractor will establish an integrated data collection system, conduct field verification of sample installations, and track saving values to ensure goals are being achieved.[60]

e. **Conclusions**.

(1) Since UNSE is managing this program, the Budget shows $12,000 as "Subcontracted Marketing Expense" and many other expenses summarized in Table below.

Table 4 – Subcontractor and other Expenses that are not Appropriate.

Budget Items for Subcontractors (ONLY)	Budget
Admin, Managerial and Clerical Labor Subcontractor Labor	$9963.00
Admin, Travel & Direct Expenses Subcontractor Travel, Conferences	$812.00
Overhead (General & Administrative, - Labor and Materials Subcontractor :Labor – Regulatory Reporting	$567.00
Marketing/Advertising/Outreach Internal Marketing Expense (Note 1)	$12,000.00
Marketing/Advertising/Outreach Subcontractor Marketing Expense	$4800.00
Hardware and Materials – Installation and Other DI Activity Subcontractor – Literature, Education, Energy Mgt tools, etc.	$4840.00
Rebate Processing and Inspection – Labor and Materials Subcontractor Labor – Rebate Applications, Field, processing	$7680.00
EM&V Labor and Materials Subcontractor Labor – EM&V	$7,290.00
TOTAL Subcontractor TOTAL Internal Marketing Expenses	$35.952.00 $12,000.00

Note 1: All Education and Outreach Activites are included the Education and Outreach DSM Program, thus these expenses are not appropriate.

(2) In Appendix 3 of this plan,[61] the following are potential errors:

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60 *Ibid.* at 5.

61 *Ibid.*, Appendix 3, Measure Level Energy Savings and Benefit/Cost Analysis, at 15 and 17.

(a). In both the effectiveness charts, when an air conditioner had a 17 or 18 SEER, show no incentives while the program states that incentives are for 16 and greater SEER.[62] For each SEER rating increase of 1.0, energy requirements decrease by 10%.

(b) The Benefit/Cost chart for air conditioning systems with heat pumps should provide savings in Therms.

(c) The line loss is 10.69% which does not agree with the line loss from the test year.

(d) The rates for electricity, peak and non-peak, do not agree with the proposed rates.

f. Recommendations.

(1) That $35,952 of subcontractor expenses and $12,000 of internal marketing expenses for a total of $47,952, should be deleted from this Program's Budget since (a) the program does not call for a subcontractor; (b) marketing expenses are in the Education and Outreach DSM Program; and (c) other company recurring expenses should be reduced.

(2) That the charts in Appendix 3 include 17 SEER and 18 SEER incentives and that for heat pumps, savings in therms should be included and line loss and electricity and natural gas rates reflect what is proposed by UNSE which use the same TOU peak, shoulder, and non-peak rate schedules when computing annual values.

(3) Incentives should continue to increase as SEER ratings increase, with the Company deciding if the rebate should be accelerating, remain at same incremental change, or decelerate.

(4) "The Commission shall determine whether a utility may be allowed to recover lost net revenue."[63] The Commission has not made this decision for this program.

3.7 Shade Tree DSM Program (EC).

a. Scope. This energy conservation (EC) program promotes conservation and environmental benefits associated planting low-water usage trees. These shade trees are to be located within 15-feet on the south, west and east sides of homes. This also is a UNSE "community service" program. The incentive will be a rebate by UNSE of $30.00 for two trees of 15 gallons or larger sizes per ratepayer, once a year. USNE does not have an assessment of the impact of reducing loads or energy savings potential through shading from trees. The ratepayer will be required to plant and water the tree(s).[64]

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[62] *Ibid.*, Table 1 at 4.

[63] ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1 Draft Demand-Side Management Rules, R14-2-1709.B.

[64] UNSE DSM Programs (13 June 2007), Attachment 6, Shade Tree Program at 1-2.

The benefits of this program include:[65]

(1) The annual peak demand reduction is significantly delayed as the trees mature, zero.[66]

(2) There is no estimate of peak reduction.

(3) A total annual reduction is 140,280 kWh in reduced demand and XXX Therms in 2008 and remaining level through 2012.

(4) The annual rebates, at $65.00 per tree ($65,000/1000 trees) is constant from 2008 to 2012.

(5) The TOTAL reduction of green house gas (GHG), other air pollutants and saved water, from 2008 to 2012, based on "historic program performance:"[67]

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved
CO_2	1,140,475	SO_2	547	Water	XXX gallons
NO_x	1,768	Ozone	XXX	Mercury	XXX oz

(6) At a month DSM Adjustor surcharge of $XX.XX per kWh per residential customer for this program, or an average bill of $X.XX for monthly usage of XXXX kWh.

(7) This program has a societal test benefit effectiveness ration of 1.41

b. Reference. (1) USNE DSM Programs (13 June 2007) Attachment 6; (2) Gregory McPearson and James R. Simpson, *Desert Southwest Community Tree Program*, 2004.

c. Program Requirements. USNE will provide media coverage in its Education and Outreach Program at 3.2. Each ratepayer receives a cash incentive of $30.00 a tree, to $60.00 a year, from either a participating retailer or directly from UNSE. It is estimated that 1,000 trees will be planted annually, with a 30% attrition rate. Only Palo Verde and Mesquite trees are permitted

d. Program Performance Measurement. There are none. The proposed program has a repeated and not relevant section on Monitoring and Evaluation. It is not expected that UNSE field personnel will check customer's yards to verify UNSE "shade trees".[68]

e. Conclusions.

(1) Trees consume water and lose water by transpiration to the atmosphere. Mesquite trees were imported by cattle to Santa Cruz Valley in the 1890s and are very hard to kill or remove as their I roots grow to about 35- to 40-feet removing all water from the soil The ADWR Santa Cruz Active Management Area (SCAMA) Ground Water Users Advisory Council (GUAC) has explored ways to remove the tens of thousands of unwanted Mesquite as a way to sustain water resources without success. I attend the monthly GUAC meetings, probably the group with most significant impact in this county, as 100-year assured water

[65] Based on the recommendations below, the existing benefits will change, thus it is recommended that all the XXX's in this subparagraph be completed in the applicant's Rebuttal.

[66] UNSE DSM Programs (13 June 2007), Attachment 6, at 5.

[67] *Ibid.* Table 4 at 5. This performance might be for mature trees.

[68] *Ibid.* at 3

supply (AWS) certifications depend on maintaining sustainability in SCAMA for building permits. SCAMA, which corresponds to the UNSE service area, presently has about 50,000 persons. The Santa Cruz County Comprehensive Plan and ADWR estimate that this valley can sustain about 71,000[69], after which no building permits with 100-year AWS will be granted. Only about 30% additional population growth remains in this county. This county has only water source, the Santa Cruz River, mostly flowing underground. Last week, at the monthly SCAMA GUAC meeting, the Assistant State Drought Director from ADWR, in a drought update briefing for SCAMA, stated the drought in Santa Cruz County is expected to last at least eight more years due to ongoing Pacific Ocean currents involving El Niño, La Niña and the California Current upwelling pattern changes.

(2) Mesquite and Palo Verde trees are not noted for producing much shade in its early years, requires pruning of dead branches, and in dry and hot weather sheds to conserve water.

(3) Our local fire district has been emphasizing the University of Arizona FIREWISE program for most residents. Significant to extreme fire danger are common during certain seasons. All homes owners were requested to remove all vegetation within 30-feet of all structures. Porches, awnings, and sun-shade boxes all reduce heat entering the exposed walls and widows, safer than shade trees.

(4) The comments about Santa Cruz County appear applicable in Mohave County, where recent reports indicate that ADWR is extremely concerned that 2/3rds of the proposed housing northwest of Kingman that may not have sustainable water resources based on supply versus demand in that area.

f. Recommendations.

(1) Based on these conclusions, this program is **NOT** recommended as water dominates other environmental issues in both counties, the overhead costs are too high, which results in each tree costing ratepayers $65 for a $30 rebate, and trees with 30 feet is contrary to FIREWISE practices. This appears more as UNS "community relations" program and should be funded by shareholders, not by ratepayers. The Societal Benefits appear for fully grown trees and not appear relevant to the 2008-2012 period of this program.

3.8 Commercial Facilities Efficiency DSM Program (EE).

Scope. This energy efficiency program is targeted to any small, non-residential commercial business with incentives to reduce payback to one year or less and total loads of less than 100 kW. The objectives of this program are to encourage small business customers to install EE measures in existing facilities. This program is designed to (1) encourage

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[69] *Santa Cruz County Comprehensive Plan, 2004,* Water Resources Element at 64.

installation of EE lighting equipment and controls, HVAC, and refrigeration systems; (2) encourage contractors to promote this program and provide turn-key installation services; (3) Overcome market barriers to reduce first costs, increase awareness and EE performance uncertainty; (4) Assure a clear participation and implementation processes.[70] Customer education and contractor training are included, see 3.2. UNSE will monitor "avoided costs".[71]

The incentives are to reduce between 45% and 85% of the cost of a selected group of "retrofit and replace-in-demand" (ROB) EE measures in existing or new facilities. The annual incentive cap of $10,000 applies to all customers. The EE measures include high-efficiency lighting upgrades, high-efficiency HVAC equipment, lighting controls, programmable thermostats, and selected refrigeration measures as shown in Table 5:

Table 5 – Commercial Facilities Efficiency Measures and Associated Rebates.[72]

LIGHTING MEASURES	
De-Lamping and Replace T12 Systems & Magnetic Ballasts with T8 Systems and Electronic Ballasts	$25 to $45 per fixture
Energy Efficient Integral Compact Fluorescent Lighting (screw-in CFL)	$7 to $10 per lamp
Replace Incandescent and CFL Exit Signs with LED lighting	$60 per sign
Install Occupancy Sensor controls on Lighting Fixtures	$65 per system
HVAC MEASURES	
Replace standard thermostats with Programmable set-back Thermostats	$100 per thermostat
High-Efficiency Packaged Air conditioners and Heat Pumps (<65,000 BTU)	$75 to $350 depending on size and SEER rating
REFRIGERATION MEASURES	
Integrated Refrigeration Case Control and Motor Retrofit	Up to $6,200 per site
Refrigerated Case Evaporator Fan Controls	Up to $2,500 per site
Install Anti-sweat Heater Controls	Up to $1,300 per site
Evaporator Fan Motor Retrofit with high efficiency motors	$125 per PSC Motor $150 per EC motor

The benefits of this program include: [73]

(1) An annual peak demand reduction of 428 kW in 2008; increases to 488 kW in 2012.[74]

(2) This peak reduction equals capital savings of $299,600 (428x700) in capital peaker generation faculties to save the Company capital costs at $700/kw for a gas turbine in 2008 and $314,600 (488x700) in 2012.[75]

(3) A total annual reduction of 2,219,100 kWhs energy saving in reduced demand and XXX Therms in 2008, increasing to 2,533,296 kWh energy with XXXX Therms in 2012.[76]

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[70] UNSE DSM Programs (13 June 2007), Attachment 7 at 1.

[71] *Ibid.* at 1.

[72] *Ibid.* at 4 and Table 1 at 5.

[73] Based on the recommendations below, the existing benefits will change, thus it is recommended that all the XXX's in this subparagraph be completed in the applicant's Rebuttal.

[74] *Ibid.*, Table 3 at 7.

[75] *Ibid.*

(4) The annual implementation cost of $17,021 per $10k participant ($400,000/23.5) in 2008 decreasing to $16,767 per $10k customer ($450,204/26.85). Assuming a $10,000 rebate limits this to 23.5 participants in 2008 and 26.85 in 2012. The Cost/Benefit ratio is 1.7 decreasing to 1.68, both very high.

(5) The TOTAL reduction of green house gas (GHG), other air pollutants and saved water from 2008 to 2012 is estimated to be:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved
CO2	19,542,947	SO2	9,37	Water	XXX gallons
NOx	30,288	Ozone	XXX	Mercury	XXX oz

(6) At a month DSM Adjustor surcharge of $XX.XX per kWh per residential customer for this program, or on an average bill of $X.XX for monthly usage of XXXX kWh.

(7) This program has a society test benefit effectiveness ratio of 2.72.[77]

b. References. (1) UNSE DSM Programs (13 June 2007), Attachment 7; (2) California DEER database; (3) a detailed southwest desert climate model; (4) industry data and resources, such as CEE and ASHRAE; (5) manufacturer's data; (5) other regional data.[78]

c. Program Requirements. Small businesses with less than 100kW loads, submit proposals by mail or on-line to UNSE to evaluate. Proposals are evaluated based on Total Resource Cost (TRC) with customized measures from Table 5 so each approved project meets the TRC test.[79] The program will offer consumer and contractor education and information to make decisions to improve EE of lighting, HVAC, and refrigeration systems. Contractors will be qualified Arizona Registered Contractors and be required to complete a UNSE sponsored orientation and pre-installation training qualification program. Incentives paid to contractors may offset up to 100% of a project's installation costs. USNE will provide an in-house program manager to lead this program in all areas including administration, proposal and incentive processing, monitoring installing contractors, track and report program status, manage quality control and the delivery process. UNSE will outreach to contractors and the owners of target commercial facilities primarily on the web, and provide education and training as described in 3.2 for this program. Installing contractors will provide turn-key systems to UNSE's ratepayers.

d. Program Performance Measurement. UNSE will collect data, maintain a progress tracking database and provide periodic reporting. UNSE with its implementation contractor will establish

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76 *Ibid.*
77 UNSE DSM Programs (13 June 2007), Attachment 7, Table 5, Benefit-cost analysis results at 8.
78 *Ibid.*, at 3.
79 *Ibid.*, at 1.

an integrated data collection system, conduct field verification of sample installations, and track saving values to ensure goals are being achieved.[80]

e. Conclusions.

(1) This program has the highest payback of the proposed UNSE DSM programs; however, assuming that all are $10k participants, only 28.5 customers can participate. Additional benefactors should be included by having the Company lower the present high administrative and marketing costs. UNSE should work with promotional and installing contractors so they become "EE believers" who see the benefits to themselves and their clients. Once that happens, there should be adequate proposals to maximize all funds in the budget and UNSE "marketing" efforts should be minimal.

(2) Many overhead costs should decrease after this program implementation as most of its features appear designed to be self-actuating to lower labor costs in year's two to five.

(3) A sample (1) Commercial Facilities Efficiency Proposal (format as a minimum) (2) Installing Contractor Agreement with UNSE; and (3) On-line Project Completion Report formats, instructions, and form-fill-ins should be a new Appendix to this Attachment.[81]

(4) The Proposal "evaluation" process is briefly discussed and important to all participants.

f. Recommendations. It is recommended

(1) That UNSE treat the contractors as team players, partners so their customers, UNSE ratepayers easily see that rapid payback with significantly lowers cost. Even a low-interest USNE "loan" or payment plan could also incentivize more program participation.

(2) That the proposal evaluation process should be objective, tied to realistic and measurable performance objectives, DSM goals, in an open environment so that proposal selection validates the need to meet this program's requirements so that each proposal evaluation will be without protest.

(3) That "the Commission shall determine whether a utility may be allowed to recover lost net revenue."[82] The Commission has not yet determined if it will support this program.

(4) That more EE elements can be added to this program, so repeat participants still improve electricity efficiency in their companies so that new contractor trades can participate.

(5) That this program be approved.

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[80] *Ibid.*, at 9.
[81] *Ibid.*, Appendix 3
[82] ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1 Draft Demand-Side Management Rules, R14-2-1709.B.

Part IV – ISSUES

Administrative Rules and Regulations, Changes in "Connect" Fees, Billing Schedules, Predatory Loan/Check Cashing Facilities as Billing Agents, Revised Billing Statement and R&R Publication

4.1 This is a Group of Related Issues.

This group involves several inter-related issues that have been grouped as one issue. Each is discussed individually in the following sections.

In general, these are identical issues that remain open in the parallel UNS Gas Rate Case where Direct, Rebuttal, Surrebuttal, Rejoinder, and Summary Testimonies have been filed, eight-days of oral testimonial hearing held, and Initial and Briefs filed by the same parties as in this case plus an intervenor from the Arizona Community Action Association (ACAA), who represented low-income programs in three northern Arizona counties excluding the UNSE Electric service areas. The Administrative Law Judge was also different than in this case.

In Part IV, each of these issues is briefly presented along with differences between the UNS Gas and UNS Electric cases, mostly, administrative, such as different paragraph numbers in the proposed Rules and Regulations.

For reference, in the UNS Gas Magruder Reply Brief found in Exhibit B, all of these issues are presented with final recommendations.

Issues. These issues are identical to the same issues in Exhibit B, section 2.6. The UNS Gas filings and transcripts have not been submitted in this UNS Electric case, ACC Docket Nos. G-04204A-06-9463 (the UNS Gas Rate Case) nor are they essential to understand the issues and associated recommendations.

The following changes are generic throughout Exhibit B.

(1) Change Gas to Electric

(2) All references and discussions about "changes in 'connect' Fees issue" or "additional connect charges" do NOT apply to UNS Electric and should not be considered.

(3) Footnotes have been renumbered to agree with this filing.

(4) A prefix "B" has been added to all Tables.

4.2 Administrative Rules and Regulations.

In general, all of the issues in Part IV pertain to changes in the Company's Rules and Regulations (R&R).

4.3 Changes in "Connect" Fees.

This is not an issue in these proceedings and any such reference should not be considered.

4.4 Billing Schedule.

See Exhibit B, which provides the basis, discussion and recommendations to changes proposed to the billing schedule. No changes in testimony or recommendations from that in Exhibit B are necessary. The referenced R&R sections in the UNS Gas R&R Section 10.C become Section 11.C in the proposed UNS Electric R&R.[83] References to UNS Gas R&R Section 11.E becomes Section 12.D in UNS Electric R&Rs.

4.5 Predatory Loan/Check Cashing Facilities as Billing Agents.

See Exhibit B, which provides the basis, discussion and recommendations to the proposed changes in billing statements which refer UNSE ratepayers to such facilities who have been hired at UNSE billing agents. It is not appropriate to use possible predatory loan/check cashing facilities as UNSE billing agents for lower income ratepayers to pay their bills. No changes in testimony or recommendations from that in Exhibit B are necessary.

4.6 Revised Billing Statement.

See Exhibit B, which provides the basis, discussion and recommendations to changes proposed to the billing statement sent monthly to UNSE ratepayers. No changes in testimony or recommendations from that in Exhibit B are necessary. There were fourteen recommendations to revise the new billing statement presented in the UNS Gas Rate Case. Since the billing statements for UNSG and UNSE are very similar, these same detailed recommendations apply. These details will be presented as a Magruder Exhibit during oral testimony.

4.7 R&R Publication.

See Exhibit B, which provides the basis, discussion and recommendations to publish the ACC-approved UNSE Rules and Recommendations (R&R). No changes in testimony or recommendations from that in Exhibit B are necessary. Only Table B-3 in Exhibit B has been changed to reflect the UNS Electric R&R Section Titles.

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[83] Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, Inc., of 15 December 2006, Exhibit TJF-1, at 82.

Part V – ISSUE

Costs to Improve Electricity Reliability in the Santa Cruz Service Area

(Testimony on this issue needs additional information from USNE)

5.1 Reliability Issues in the Santa Cruz Service Area.

5.2 Improvements Initiated by UNSE in the Santa Cruz Service Area.

5.3 Cost of the USNE Reliability Changes.

5.4 Estimated Cost of proposed UNSE Changes

5.5 Conclusions

5.6 Recommendations.

Part V – ISSUE

CARES and CARES-M Tariffs

(Testimony on this issue needs additional information from USNE)

6.1 Concerns about CARES and CARES-M Programs.

6.2 CARES Participation.

6.3 CARES-M Participation.

6.4 Recommendations to Improve the CARES Tariff.

6.5 Recommendations to Improve the CARES-M Tariff.

EXHIBIT A

RESUME OF MARSHALL MAGRUDER

Education

MS in Systems Management, University of Southern California, Los Angles, California (1981)
Majors in Managing Research and Development and in Human Factors (grade A in every course)
MS in Physical Oceanography, Naval Postgraduate School, Monterey, California (1970)
Honor roll 4 times (two years, 5 terms a year)
BS, US Naval Academy, Annapolis, Maryland (1962)
Special courses in Operational Analysis and History of Russian Military Tactics

Experience

Over 25 years as Senior Systems Engineer with and an associated contractor, consultant to Raytheon-Hughes in systems engineering, training and naval systems, simulation and modeling in C4I; with over 20 years of service with the US Navy, a total over 40 years experience in this field

- **Large-system development** at all levels
  From pursuit, analysis, winning strategy, Request for Proposal evaluation, proposal management, system requirements analysis, architectures, specifications, design synthesis, trade-off studies, requirements allocation tracking,
  To system, level test planning, deployment, implementation, through sign-off, and
  For technical systems of all complexities.

- **Developed** Antisubmarine Warfare (ASW), Electronic Warfare (EW), Command, Control, Communications, Computers, Intelligence, Surveillance, and Reconnaissance (C4ISR) operational concepts, procedures, and tactical employment.

- **Used, operated, and planned** Navy, Army, Air Force, Coast Guard, Joint systems, world-wide.

- **Coordinated multi-platform employment** from sensor to unit to Battle Force to Theater levels.

- **Qualified systems engineer/manager** for trainers, artillery, Command and Control (C2), countermeasures, for any platform.

- **Specialties:** environmental analysis, documentation, sensor/weapon predictions, C4ISR, Electromagnetic and Emission Control decision criteria.

- **Battle Force/Group Tactical Action Officer** (TAO) on 8 aircraft carriers, TAO Instructor for 4 years, 20 months combat experience.

Recent Positions
at ImagineCBT Inc., ISIS Inc., Raytheon and Hughes Aircraft Company

C4I Architect and **C4I Support Plan Lead** for the Carrier for the 21st Century (CVNX) Task Order.
- Completed *CVX C4I Support Plan, v1.0,* Joint Operational Architecture development for Joint and Naval staff space allocations for CVX (1999) and Joint Command and Control ship (2002).
- Drafted *CVN 77 Electronics System Integrator Statement of Work (SOW)* for WBS Group 400 tasks and IPTs (1999), *Integrated Management Plan*; Royal Navy CVF WBS proposal (2002)

Lead Systems Engineer, Operations Analyst and **Site Survey Leader** for Saudi Arabian Minister of Defense National Operational Command Centers and C4I System (completed August 1997).

- Completed *System Specification, System Description Document, Site Survey, Interface Requirements Documents*

Proposal Technical Volume Manager for the following **winning proposals**:

- Vessel Traffic Service 2000 system, US Coast Guard command center for surface surveillance using radar, visual, communications links. (proposal evaluated A++, won Phase I, Phase II delayed then restructured)
- Anti-submarine Warfare Team Trainer (Device 20A66), an integrated, multi-ship, submarine and aircraft training system for Naval Task Groups. ($56M contract, best technical, lowest cost)
- Electronic Warfare Coordination Module, an Intelligence/EW spectrum planning and management system for Task Force Command Centers. (won Phase I, best technical)

Assistant Program Manager for the Training Effectiveness Subsystem, Device 20A66

- Performance Measurement Subsystem, observed real-time performance of operators, teams, multi-ship and aircraft units during exercises and compared to the standard

Senior Systems Engineer responsible for writing **specifications** in following **proposals**:

- Fire Support Combined Arms Team Trainer (FSCATT) *System Specification*, a US Army artillery multiple cannon and battery training system. (awarded $118M contract, still under contract)
- Warfighter's Simulation 2000 (WARSIM 2000) *System Specification*, a US Army Force XXI Century battalion to theater levels, and training system with actual C4I systems. (won Phase I)
- Tactical Combat Training System, *Exercise Execution Software Requirements Specification* (SRS) for simulation and computer models to run real-time, driving sensors, weapons and links on 35 ships, 100 aircraft and submarines (won Phase I contract, wrote SRS in Phase 2 proposal)

Detailed Descriptions of Experience

The following are more information, arranged chronologically, with dates, duration, position title, program name, followed by accomplishments, and then an overview of the project.

April 2000 to present – ISIS, Inc., primarily as Senior Scientist, Information System Architect, Systems Engineer, Training Systems Analyst and **Requirements Analyst.**

General Accounting Office (GAO) (May 2005 – June 2006), reviewed and prepared training system development and professional engineering services (PES processes and job descriptions for category 69 (training) proposal.

Strategic Services and Support (April 2005-Sept. 2006), attended pre-solicitation conference for the Army Communications-Electronics Command (CECOM), Ft. Monmouth, New Jersey, waiting for formal request for a part of this $19.25 billion program proposal.

Department of Interior Management, Organization and Business Improvement Services (MOBIS) and Professional Engineering Services (PES) proposal analysis (June 2005), prepared a detailed requirements and tasks analysis of the RFP) and proposal plan.

Total Engineering Information Services (TEIS) (Feb. – March, 2005), participated as proposal writer, pink and red team member with another company which is prime for an approximately $12 million, multi-year, contract for the Army Information Systems Engineering Command, Ft. Huachuca, Arizona. Prepared TEIS Risk Management Plan for prime contractor. Presently ISIS is waiting for announcement of selected winners.

Networthiness Certification (Jan. 2005 – Sept. 2006), prepared proposal for the Army Network Command (NETCOM), awaiting RFP to respond for this several million dollar program involving over 3,200 Army computer programs at all Army installations, worldwide. Prepared Quality Control (QC) and Risk Management Plan.

Cryptologic Support and Logistic Analysis (Oct. 2004 – Sept. 2006), prepared proposal for the Army Communications-Electronics Command (CECOM), Ft. Huachuca, Arizona, waiting for formal request for proposal.

Information Warfare Training (2001 - 2005), USAF Small Innovative Business R&D (SBIR) Phase I contract, to determine IW training requirements and measure performance in an intelligence, wargaming system, awaiting possible award for development of an Information Warfare training system for the USAF Information Warfare Aggressor Squadron.

US Army Virtual Proving Ground (2001-2002) - Performed *C4ISR Architecture Framework* development, implementation and documentation using the DoD *C4ISR Architecture Framework, v2.0* and for Operational, Technical and Systems architecture products.

Prepared C4ISR architecture framework proposals for US South Command (USSOUTHCOM) Command Center (2003), DoD Threat Reduction Agency (DTRA) Operational Command Center at an Army Command, Virginia (2002), and Government Enterprise Architecture development for Department of Health and Human Services Command Center (2002) programs.

Raytheon Naval and Maritime Systems, San Diego, California, for various programs, a consultant for ImagineCBT, systems engineer.

April 2001 to June 2005 – C4I Architect, Operations Analyst/Systems Engineer for Minister of Defence (UK) Future Aircraft Carrier (CVF) program, Raytheon Naval and Maritime Ship Systems, San Diego.

Prepared for Raytheon Naval Ship & Integrated Systems (San Diego) proposals in April and June 2003 with Statement of Work (SOW), Data Item Descriptions (DIDs) and CDRLs for Architecture Assessments (Requirements, Testing) for ten functional mission areas, Global Information Grid Evaluations in order for CVF to be interoperable with US forces, and Levels of Information System Interoperability (LISI) using DoD LISI PAID (procedures, applications, infrastructure, data) attributes to determine internal and external interoperability assessments

Prepared proposal and performed contract for Raytheon C3I Systems (Fullerton, CA) for the Joint Command and Control Ship (JCC) *JCC Interoperability Study*, including report drafting and preparation, conference presentations and making recommendations to JCC Program Office for ensuring over 400 tactical, logistic, administrative, C4ISR applications work. (2001-02)

Prepared proposal and performed contract for Raytheon NAMS (San Diego) for *JCC Reconfiguration Study* to determine requirements to most effectively manage command (C4ISR) onboard JCC. (2001-02)

Provided architecture framework proposal inputs and evaluation for US Army Landwarrior III (Future Combat System) for Raytheon C3I Systems (Plano Texas)

Provided C4ISR and engineering analysis and proposal preparation for LHA(R), JCC, CVF and other Raytheon, San Diego ship programs (2000-03)

October 2000 to present (inactive) – MBA Instructor, University of Phoenix, for "Operations Management for Total Quality" and "Managing R&D and Innovation Processes" courses.

Taught these courses in Nogales to Mexican maquilladores managers and in Tucson to Americans managers.

Qualified to teach "Program Management" course.

Plan to qualify as FlexNet (online) Instructor, presently inactive instructor status.

April 1998 to September 2000 – CVNX C4I Architect, C4I Support Plan Leader also **Lead Systems Engineer** and **Requirements Analyst** for CVN 77 and CVNX Programs, at Raytheon, San Diego, CA

Performed C4I Support analysis to prepare requirements for the DoD C4I Support Plan. Led several teams to understand the *DoD C4ISR Architecture Framework*, v2.0 and Operational, Technical and Systems architecture products.

Managed team for CVN 77 combat requirements analysis 3 months to draft and submit plan to NAVSEA (PMS-378) for two customer reviews.

Provided interface to combine CVNX and Joint Command and Control (JCCX) Ship architecture development for NAVSEA (PMS-377), drafted task schedule but funding then not provided.

Proposed an approved Technical Instruction for "Reconfigurable Joint and Naval Staff Space Allocations" in order to start the CVX/JCC *Operational Architecture* and *Mission Essential Tasks* processes – completed early 1999. (3 of 14 proposed were approved for study)
Coordinated the AFCEA "Architecture Implementation Course" at the Raytheon San Diego site.
Created and drafted CVN 77 *Electronic Systems Integrator (ESI) Statement of Work (SOW)* for the CVN 77 ESI role and RFP in Spring 1999.
Provided trade studies and options for performing this task for Newport News Shipbuilding.
Established a draft CVN 77/CVX "Total Ship Systems Engineering (TSSE) Plan for our team.
Implemented the Raytheon and Newport News Shipbuilding *Integrated Product and Process Development* processes to structure IPTs, tasks, and work descriptions.
Provided interoperability inputs to UK Future Aircraft Carrier (CVF) Raytheon Qualification letter.
Participated in establishing teaming arrangements with SPAWAR Systems Center, San Diego.

The CVN 77 is the transition aircraft carrier from the *Nimitz* class, to be commissioned in FY 2008. Two other evolutionary aircraft carriers, CVNX-1 and CVNX-2 are to be commissioned in FY 2013 and FY 2018, respectively. The tenth CVNX is planned for disposal in FY 2111. Overall manning will be reduced up to 1,740 personnel. Up to 12 Joint, Naval, Combined and Coalition staffs may embark up to 1,000 augmentation personnel beyond the present capabilities. CVNX can embark a Joint (Task) Force Commander with command and control systems for Operational-Theater and Tactical (service) levels. The ESI role involves integration of all C4ISR equipment, internal and external communications, navigation, sensors, fire control, weapons, and associated display and processing systems.

January 1998 to present – H&R Block, Tax Advisor Level 3, seasonal tax preparer (annually, January to April 15), AARP Tax Consulting for the Elderly (pro bono) tax preparer, IRS qualified, over 450 hours of H&R Block classroom and CBT training courses.

August 1997 to April 1998 – DD 21 Requirements IPT Lead, Systems Verification and Test IPT Lead, and **Initial Lead Systems Engineer** for the Hughes, then Raytheon, DD 21 Program for NAVSEA, PMS-500 – assigned the CVX Reduced Manning (Automation) Study that led to CVX C4I Support Plan after Raytheon sent "no bid" letter in April 1998.
Provided IPPD plans for all systems engineering functions, including workshop participation, for subsystem to total Ship System levels.
Managed two Integrated Product Teams (IPTs), as additional DD 21 personnel were assigned.
Conducted a weekly VTC with IPTs, issued Agenda, Minutes, and led team meetings.
Attended Risk Management course and recommended Raytheon's Prophet™ risk management software tool for DD 21 and other integration programs.
Provided the initial *DD 21 Total Ship Systems Engineering (TSSE) Plan*.
Coordinated systems engineering modeling and simulation planning.

The Future Surface Combatant of the 21st Century (SC-21) Program consisted of both destroyers and cruisers, with the Land Attack Destroyer (DD 21) to be commissioned in FY2009 and an Air Dominance Cruiser in FY2018. I participated in the program implementation and maintenance of collaborative and synergy with both CVNX and SC-21 programs and the emergent JCC and USCG Deep Water Programs. [SC 21 is DDGX Program]

June 1995 to August 1997 (26 months) – Operations Analyst and **Site Survey Team Leader** also **Naval Operations Analyst** and **Joint Training Analyst,** *C4I System for National Defense Operations Center and Area Command Centers Definition Study* **- completed August 1997.**

Performed pre-contract planning analysis for site survey from battalion to national level.
Managed budget for 3 months deployment for the 12 engineers in Saudi Arabia.
Conducted interviews and briefs with members of all joint Minister of Defense and Aviation (MODA) staff and all armed forces, including schools and topographic commands.

Provided reports, program reviews and TGMIRs for survey and design efforts for the 2 years, including the coordination of all Action Items and Program Management Review Minutes.

Created significant inputs to the *System Description Document, System Specification* as Lead Systems Engineer, emphasized operational concepts including staffing and workstation operator tasks; operations center and support facility layouts; specifications for a transportable operations center (TOC); system-level communications interfaces including ATM, SATCOM, PTT and RF communications; system hardware and software interfaces including JMCIS, TADIL-S and IDL; operator training; selected over 100 formatted messages (using USMTF) for integration, and overall system performance characteristics.

Drafted System Specification for Land Forces Operations Center, deemed excellent by customer.

Prepared *Site Survey Report* and participated in drafting the *Communications Interface Requirements Document*, presented multiple customer briefs.

Only engineer to start and complete this contract (over $10M), most of the others were replaced.

The MODA C4I System will provide 13 operations centers, nation-wide, to form a joint service, C4I system, integrating the four services through 3 command echelons and, for the Land Force will provide their digital command and control system through 4 echelons.

1995 – Systems Engineer, for an AirHawk Concept of Operations.

Drafted a preliminary "*Operations Concept Document (OCD) for the Air HAWK*" system for HMSC, provided a systems approach to integrate the subsystems with the missile, for the Command and Control Division, using the MIL-STD-498(B) DID as a guide.

AirHawk provides an air-launch system capability for the U.K. Tomahawk cruise missile.

1995 (5 months) - Lead Systems Requirements Engineer, Warfighters' Simulation 2000 (WARSIM 2000), US Army training system.

Performed system functional requirements analysis for command and control levels from battalion through echelons above corps and Theater-levels

Responsible Engineer for the analysis and writing of the system specification for the entire system in accordance with MIL-STD-498(B) (System Engineering). (Hughes won Phase I)

WARSIM 2000 C4I training system to stimulate all present and emerging Force XXI digital C4I systems with operational data for entire staffs in their Tactical Operations Centers in the field, in classrooms and at the War Colleges. WARSIM 2000 integrates with other joint systems through protocol standardization and object-oriented design features.

1994 – System Requirements Compliance Engineer, Theater Battle Management Core System (TBMCS), US Air Force C4I system.

Ensured compliance with the contract and requirements documents integrating different systems into the TBMCS proposal, including the Global Command and Control System.

Drafted a compliance matrix with 200 pages in the Executive Volume to meet demanding RFP compliance requirements (Proposal vs. IFPP vs. SOW vs. CDRL vs. WBS vs. CLIN vs. TRD).

TBMCS is the US Air Force Theater to squadron level C4I system. (Hughes lost)

1994 (7 months) – Proposal Technical Volume Manager for the Vessel Tracking Services 2000 (VTS 2000), US Coast Guard C3 system.

Led the technical and engineering proposal efforts to comply with the RFP and proposal requirements, based on Hughes themes and proposal strategy decisions.

Managed systems, hardware, communications, software, and logistics engineers writing the responsive proposal. (Ten corporate teams bid; Hughes won Phase I with two others including Raytheon, Hughes performed Phase I, Congress delayed Phase II, program later restructured)

VTS interfaces radar, visual surveillance, environmental, and voice communications data with differential Global Positioning System (dGPS) information from automated and human input to enhance safety and commerce on waterways and for major port regions.

1993-1994 (10 months) – Lead Systems Engineer, Fire Support Combined Arms Tactical Trainer (FSCATT), US Army training system.

Team Leader for the requirements analysis, design, and system engineering and proposal efforts.

Drafted and led several pre-RFP System Requirements Reviews for the System Specification.

Developed a technique with Distributed Interactive Simulation (DIS) protocols whereby a thousand or more cannons can perform exercises from multiple sites in same exercise.

FSCATT integrates artillery and fire control with a Forward Observer visual training system, provides Fire Direction Center simulation and stimulation interfaces with Close Combat Team Trainer (CCTT) M1 tank and M2 systems. (Hughes won $118M program, still ongoing)

1990-1991 (20 months) – Systems Requirements Engineer, Tactical Combat Training System (TCTS), US Navy C4I training system.

Led the simulation and modeling, system requirements analysis for all real-time operations for the proposal and Phase I development efforts. (Hughes won Phase I)

Wrote most of the *Exercise Execution CSCI SRS* for real-time system execution software for all simulations and sensor, weapons and platform models (over 100).

TCTS provides a task group training data link for 100 aircraft, 24 ships and submarines, 6 ashore installations and ranges, with real-time targets (to 780). TCTS uses participant "pods" with a data link between platforms; stimulates platform sensors with the real-time targets; maintains data link communications; collects data for feedback and rapid after action reviews. (Hughes team won Phase I, Raytheon Phase II)

1991 - Human Factors SE for Land Warrior 2000 proposal, US Army infantryman C4I system.

Human Factor Engineer for proposal effort for the helmet display overload analysis with computer text and graphic display resolution. Left to lead FSCATT Systems Engineering and Proposal teams.

Land Warrior 2000 system provides infantrymen with an integrated C4I System for an infantry brigade, with computer-driven displays, messages, GPS, and other C2 features. (Hughes won)

1988-1991 (4 years) – Assistant Program Manager for the Training Effectiveness Subsystem, Device 20A66.

Created Performance Measurement Subsystem, used subcontractor to provide analysis, documentation, and design details.

Managed subcontract ($1.2M), conducted subcontractor reviews, and wrote SOWs, evaluated products and a subcontractor.

The Performance Measurement Subsystem determines operational performance (real time) for trainees from Admiral to sensor operators and for ship teams, multi-ship and tactical units.

1988-1991 (4 years) – Senior Systems Engineer, Device 20A66.

<u>Lead Systems Engineer</u>, provided significant inputs for models, simulations, communication data link interfaces, user displays, and I/O; consultant to software team as ASW expert.

Designed to real-time Links 4A/11/16 with ships in port and ships/aircraft at sea.

The Device 20A66 trains a Battle Group Commander in a Task Force Command Center (TFCC), staff and subordinate staffs (in 20 ships and submarines and 15 aircraft in 35 mockups using 186 different workstations with 61 large screen displays) to use data links, communications, and good decision making practices.

1986-1988 (1.5 years) – Proposal Technical Volume Manager, Device 20A66.

Evaluated Draft-RFP and System Specification, provided 229 change pages, and was acknowledged to be most significant pre-proposal action by any bidding contractor.

Led pre-proposal, technical design and development effort as the only engineer for 1 year.

Led, as Technical Volume Manager, team of systems, simulation, hardware, courseware, facility, logistics and software engineers in the synthesis and drafting of the 500-page technical volume, with final technical volume cost less than B&P estimate.

After proposal submittal, replied to questions, gave briefs. (Hughes won, beat 2 incumbents)

1987-1988 (6 months) – Proposal Manager, California Law Enforcement Driver Trainer System

Led pre-proposal and proposal team to develop a design for high-technology driver trainer systems for the Peace Officers and Safety Training (POST) Commission. (Hughes won)

Participated during contract, as systems engineer in-charge of design, to verify the POST training objective(s), standard(s) and criteria would be met for the drivers of the system.

1987 (4 months) – Lead Engineer, Advanced Fuels Auxiliaries Test System for USAF

Provided initial engineering requirements analysis leading to joint venture with Allison Gas Turbines to bid this major USAF test system.

Drafted initial System/Subsystem Design Document, the basis for design.

Hughes bid, after I left project; however, USAF declined to award contract.

1986-1987 (3 months) – Proposal Coordinator, USAF LANTIRN training system.

Led proposal compliance review for real-time video and infrared technical requirements using the Hughes RealScene™ 3-dimensional (voxel-based), interactive system instead of the Hughes (formerly Honeywell)-developed, GBU-15 training system.

LANTIRN trainer provides real-time displays of video and IR images to cockpit and weapons systems for F-15, F-16 flight simulators and the AGM-130 missile. (Hughes no-bid)

1985-1986 (9 months) – Senior System Engineer for the Electronic Warfare Coordination Module (EWCM) program with responsibility for the environmental effects design.

Led technical proposal effort, coordinated proposal outline, reviewed storyboards and topics, determined compliance, edited technical volume, and synchronized with other volumes.

Responsible engineer for atmospheric and acoustic effects on propagation and degradation from countermeasures, provided customer briefs and proposal topics.

EWCM provides full spectrum management capabilities for the Electronic Warfare Commander to coordinate operational and intelligence EW information and databases. (Hughes won Phase I, lost Phase II)

1982-1985 (2.5 years) – Systems Engineer for the training subsystem, Device 14A12 ASW Tactical Ship Training System.

Led technical proposal effort for the Performance Measurement and Monitoring training subsystem, sonar modeling and simulation, operator displays, fire control, data links, and sensor, weapon and platform modeling.

Designed PMM subsystem, pushing the state of the art, later implemented in Device 20A66.

All ASW ships and ASW aircraft were simulated in a single-ship, multi-dimensional (anti-air, anti-surface, anti-submarine) environment, as a C2 and sensor operator training system.

Papers

Presented papers to the Industry/Inter-Service Training Systems Conferences (I/ITSC):

"Design Concepts for a Performance Measurement System" [nominated for best paper top 5 of 105]

"A Performance Measurement System Design", based on Device 20A66 results.

Prepared and presented three reports to the National Security Industrial Association (NSIA), ASW Committee, as Vice-Chairman of Training and Interoperability Subcommittee; Study Leader for following Reports:

"Training Commonality for Oceanography and Acoustic Environment Study Results"

"Training Commonality for Detection and Classification Study Results"

"Proposed Standard Sonar Equation for Technical, Tactical, and Training Communities"
Received NSIA Meritorious Award for leading these ASW industry and government studies)
Presented paper to the Hughes Advanced Technology and Studies Group describing the use of "Distributed Interactive Simulation (DIS) Protocols in C4I Systems".

Raytheon and Hughes Aircraft Company Courses

Taught "Introduction to ASW Tactics" course, at Hughes (four times) and for the *Advanced Training Institute* at Naval Underwater Systems Center (New London and Newport RI) 10 times at the Naval Surface Weapons Center (White Oak), Naval Civil Engineering R&D Center (Oxnard), and others.

Attended "C4I Architecture Implementation" (4 days, AFCEA Course), "Risk Management" (3 days), "Front-End of the Business" (1 week), "Systems Engineering" (HITS/HMSC processes), "Global Command and Control Seminars" (APL)

Attended ATEP Courses:
Software Risk Analysis, Software Estimating and Prediction, Database Modeling, Object-Oriented Software Methodologies, Proposal Development, How to Interview Candidates, Microsoft Word, Creating a Web Browser, Netscape User's Courses

Participated in the NSIA Industry War Games at Naval War College (Newport RI) and Marine Corps Command and Development Center (Quantico).

Military Schools

Attended US Naval schools including Destroyer School Department Head Course, Gunnery Officer, Anti-submarine Warfare (ASW) Officer, Communications Security (COMSEC), Naval War College Wargaming Course, and Naval Tactical Data Systems User Courses.

Military Qualifications

Qualified for Command of Destroyer, Tactical Action Officer (Battle Group and Warship), Officer of the Deck (cruiser and destroyer), Ship Command Duty Officer, and Surface Warfare Officer.
Proven Subspecialist (post Master Degree) in Geophysics, Oceanography, and ASW Systems Technology, Board selected (about 10 in each of these subspecialties per year in US Navy).

Significant Military And Operational C4i Experience

Active duty commissioned officer in the US Navy serving in the following assignments (home ported twice with each of the four fleets):

Area ASW Force, Sixth Fleet (CTF 66) as Staff Plans Officer coordinated all surface ships, aircraft carriers, submarines and ASW/EW aircraft in the Sixth Fleet area on a daily basis; conducted operational ASW with real targets; coordinated (simulated) daily submarine, surface ship and air-launched anti-ship Harpoon attacks on targets. (Awarded Meritorious Service Medal for highest Fleet-level ASW performance ever)

Fleet ASW Training Center, Pacific Fleet, the lead Coordinated ASW Tactics Instructor and Staff Oceanographer, and at sea as an Anti-Submarine Warfare Commander Instructor and ASWC Watch Officer during Fleet Exercises, augmenting Destroyer Squadron staffs. Also taught coordinated ASW tactics at Fleet Combat Training Center (Point Loma) as a guest instructor to TAO classes for three years.

Commander Carrier Group Three, as staff ASW Surface Operations and Geophysics/ Environment Officer, deployed twice to Western Pacific and Indian Ocean; planned and conducted RIMPAC 77 with Japan, Australia, New Zealand, and Canadian ships, 3 aircraft carriers, 7 submarines and over 150 aircraft; planned Persian Gulf CENTO MIDLINK-77 with UK, Iran and Pakistan; qualified as Battle Force TAO on 5 different aircraft carriers.

Naval Surface Warfare Officers Schools Command/Naval Destroyer School as the ASW Tactics and TAO Instructor for Prospective COs, XOs, Department Heads and Free World Navies Courses for mid-grade officers from over 30 countries; co-developed Naval Tactical Analysis Wargame and used it to evaluate tactical concepts including Harpoon anti-ship tactical development; used ASW team and sonar trainers for exercises; trainers for anti-PT boat interactive team exercises; taught anti-submarine/anti-surface warfare tactics, EW, communications, and EMCON decision making classes. Taught surface ship ASW at Submarine School was a guest instructor at the Naval War College and used the War College wargaming facilities to evaluate new systems and ship classes being designed by NAVSEA. (Awarded Navy Commendation Medal with Gold Star)

Commander Cruiser-Destroyer Flotilla Ten, as ASW Plans Officer, deployed to Sixth Fleet, embarked on 3 aircraft carriers and 2 cruisers including USS *Albany*. Planned and executed many Sixth Fleet and NATO exercises and a CENTO air defense exercise. Engaged in more than 50 Soviet bomber over-flights of the Battle Group, 100% successfully intercepted by fighters and missile lock –on prior to 100 miles from the aircraft carrier. (Awarded Meritorious Unit Commendation for validating anti-SSBN tactics and developing SSN direct support procedures)

USS *Hollister* (DD788), Operations Officer, deployed for 2 years, 19 months of consecutive combat operations off Vietnam in the Seventh Fleet, provided naval gunfire support (over 28,000 5/38 rounds), maritime surveillance, SAR, *Gemini VIII* NASA space craft rescue ship, and EW intelligence gathering and Korean operations. (Awarded Secretary of Navy Unit Commendation, Navy Commendation Medal with Combat "V")

USS *Robert L. Wilson* (DD748), ASW Officer, deployed to Sixth Fleet for ASW operations, UN rescue ship off Cyprus, NATO exercises, *Gemini IV* NASA space craft rescue ship, participated in the Dominican Republic operations. (Armed Forces Expedition Service Medal)

USS *Springfield* (CLG7), Main Battery Fire Control Officer and Missile Fire Control Officer, deployed in the Sixth Fleet Flagship, home ported in Villefranche-sur-Mer, France.

State of Arizona, Industry Association, Company, and Military Awards

Arizona Secretary of State "Arizona Golden Rule Citizen Certificate" and plaque from Janice K. Brewer, Secretary of State, for "exemplifying the spirit of the Golden Rule daily: "Treat others as you would like to be treated", nominated by former Santa Cruz County Supervisor Ron Morriss, for his work as a voluntary Energy Commissioner and his work for the county before the Arizona Corporation Commission. (2004)

National Security Industrial Association. (NSIA) Anti-Submarine Warfare Committee, Meritorious Award from the NSIA President, Admiral Hogg USN (Ret.), for leading several ASW training industry and government studies. (1992)

Merit Awards. Raytheon and Hughes, four times, for achievement and excellence in performance.

Military Awards include Meritorious Service Medal, Naval Commendation Medal with Combat "V" and Gold Star, Navy Unit Commendation, Navy Meritorious Unit Commendation, National Defense Medal, Armed Forces Expeditionary Medal (Dominican Republic), Vietnam Service Medal with three Bronze Stars, Vietnam Campaign Medal with "1960-", Overseas Service Ribbon (Italy).

Community Service

Joint Santa Cruz County and City of Nogales Energy Commission from February 2001 to present – Member and Vice-Chairman and periodically report to both the Santa Cruz County Board of Supervisors, P&Z Commission and City of Nogales Council on various energy matters.

Marauder Historical Society from 2002 to present – Board Member and Vice-President, Chairman of the Living Legacy Fund Raising and Archive Donation Campaigns, semi-annual Board meetings, annual "Gathering of the Eagles" Martin B-26 medium bomber reunions since 2006, leading proponent of the "Heritage Flight" so the first World War II generation legacy is passed to later generations

Tubac Community Center Foundation from 1998 to 2000 – Member of the Board of Directors, wrote Bylaws for this IRS Code 501(c)3 organization that operates and maintains the Community Center for Santa Cruz County, softball field and play ground

Security Clearance

Active DoD Secret Clearance

Exhibit B

Excerpt from the UNS Gas Rate Case Magruder Reply Brief

to Provide Testimony about

"Administrative changes in the Company's Rules and Regulations, Changes in "connect" Fees, Billing Schedules, Predatory Loan/Check Cashing Facilities as Billing Agents, Revised Billing Statement, and R&R Publication"

The concluding UNS Gas, Inc., rate case has issues that are identical to those in this UNS Electricity, Inc., rate case. There are some minor changes in this version, for example, the footnotes have been renumbered to follow this Direct Testimony.

Below is Section 2.6 that discusses several interrelated issues, as shown by the title of the section.

QUOTE:

2.6 Administrative Rules and Regulations Changes in "Connect" Fees, Billing Schedules, Predatory Loan/Checking Cashing Facilities as Billing Agents, Revised Billing Statement, and R&R Publication

Issue. UNS Gas has proposed several administrative changes to its Rules and Regulations involving

a. Additional "connect" charges,

b. Billing schedule changes,

c. Predatory loan and check cashing facilities as bill payment agents,

d. Revised billing statement, and

e. Publication of the UNS Gas Rules and Regulations.

The Company wants to change its billing rules and regulations to be aligned with other UNS entities, **citing a 25-year old 1982 regulation**,[84] significantly decreasing allowed days before disconnection of service. The Company actively promotes pay-day loan and check cashing facilities as bill paying agents. This is extremely prejudicial to lower income customers. Table B-2 below compares these policy changes. The result is a change from 40 to 20 days, after the Due Date, before possible termination of service.

(1) <u>UNS Gas Initial Brief Changes from its Testimony:</u>

a. <u>Additional</u> <u>"connect"</u> <u>charges</u>. The Company Initial Brief summarized resolution of changes to four additional "connect" charges which involve this issue.[85] The Company also proposed that

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[84] Magruder Initial Brief, at 32. A.A.C R-14-2-310.C was last updated in 1982 according to the appropriate "historical" note. If this rule has not been enforced with UNS Gas (or Citizens), UNS Electric, TEP or Southwest Gas in these 25-years, implementation at this time should require more than a weak administrative rationale.

[85] UNSG Initial Brief, section VI.A, at 59-60.

two of its additional recommendations now be denied which involved eliminating the Incremental Contribution Study (ICS) which would reduce income by $1.2 million per year, and eliminating the $250 mandatory cost for excess flow valves after July 2008.[86]

b. Billing Schedule. The Company's Initial Brief states it

> "proposes to modify its billing terms to conform its payment terms with the Arizona Administrative Code [R14-2-310.C]. RUCO argues that this is unreasonable. RUCO, is, in effect, arguing that the Commission's own rules on this issue are unreasonable."[87]

The Company's Initial Brief goes through the timeline from when the meter is read, also the same as Due Date, to service suspension.[88]

The Company Initial Brief did not respond to the Magruder testimonies which showed a different schedule (i.e., Table B-2 below), based on understanding the revised rules.

c. Predatory Loan and Check Cashing Facilities as Bill Payment Agents. The Company Initial Brief states:

> "UNS Gas will conduct further inquires about predatory practices at payday loan business upon receiving specific information [unknown, unspecified] from the ACAA. UNS Gas is not encouraging any customers to obtain loans from these operations and ACAA presets no evidence to the contrary. UNS Gas covers any [agent's; not customer's check cashing or bill paying] fees related to the payment of gas bills at locations where it does not have an office. Further, the Company will continue its efforts to provide low-income customers with numerous options for paying their bills."[89] [inserts for accuracy, completeness and clarity]

During oral testimony Mr. Gerry Smith stated up to 790 UNS Gas bills were paid in one month at single month to a loan/check cashing agent.

The Company's Initial Brief did not respond to Magruder Testimony or Exhibit M-1.

d. Revised Billing Statement. UNS Gas has not responded to the Magruder oral testimony on this issue, in particular, to a most offensive statement printed on each UNS Gas bill:

> **"To reconnect Service after Non-Payment Pay your bill (cash only) at ACE American's Cash Experience or authorized agents"**[90]

This is offensive. Why does UNS Gas push that company on its billing statement?

e. Publication of the R&Rs. UNS Gas Initial Brief did not respond to Magruder testimony on this issue; however, earlier Rejoinder Testimony gives some Company's views on this issue.

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[86] *Ibid.* at 59.
[87] *Ibid.* at 60.
[88] *Ibid.*
[89] *Ibid.* at 57.
[90] Magruder Initial Brief, at 37

(2) Intervenor Initial Brief Views.

(a) **RUCO** stated the following about proposed Rules and Regulations

a., c., d., and e. These issues were not included in RUCO Initial Brief.

b. Billing schedule changes. RUCO initial Brief stated

> "The Company's proposal is consistent with the minimum requirements of the Commission's rules, but the only advantage to the Company that it could identify for adopting the changes was that it would bring consistency to the three affiliated utilities that are served by the consolidated call center operated by another of the affiliates."[91]

RUCO continues:

> "RUCO opposes these changes. The proposed payment dates so short that a customer could go on vacation and come home to find his gas shut off. Customers have contacted RUCO about the proposed change and expressed their opposition to it. ... Further, the Company is already being compensated (and will continue to be as a result of this proceeding) for the delay between the time bills are rendered and when they are paid as a result of its working capital allowance... the Company receives no particular benefit from the proposed change. Despite its claim that the shorter payment periods would be consistent with the affiliated electric companies, consistency across the affiliated utilities can not be fully accomplished... Therefore, even with the proposed change, call center agents would have to deal with the different issues faced by gas and electric customers... Changing the payment schedule would provide at most a *de minimus* benefit to the Company. Further, the Company is not harmed by the current schedule. However, customers perceive that they are harmed by the proposed change. Therefore, the Commission should not grant the request for the abbreviated billing terms... "[92]

(b) **ACC Staff** did not comment on any of these issues in its Initial Brief. However, earlier, the ACC Staff recommended approval of the proposed reduced billing schedule (b.) and that a

> "a temporary six-month transition period should help alleviate any hardship on customers from this change in billing terms."[93]

(b) **ACAA** did not submit an Initial Brief; however, prior ACAA Testimony covered two issues:

b. Billing Schedule. ACAA stated lower income customers usually do not have a checking account, credit cards, or the ability to pay on-line. This schedule is a challenge for those who have to pay in cash and need to arrange transportation. This leads to this class of customers, when using "payday" loan services driving, even more customers to predatory, onerous lenders.[94]

> "Twenty days is an absolutely reasonable timeframe in which to pay UES, ten days simply is not."[95]

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91 RUCO Initial Brief, at 34.
92 *Ibid.* at 34-35.
93 Magruder Initial Brief, at 34.
94 *Ibid.*
95 *Ibid.*

c. Predatory Loan and Check Cashing Facilities at Bill Payment Agents. ACAA Testimony included information about pay-day loan companies. In Arizona loans totaling over $875 million, at an average loan amount of $325, with an average fee of 17.27% with an APR of 460% resulted in nearly $155 million in loan fees collected in 2005. Additional ACAA evidence showed that a $325 loan costs the pay-day loan taker pays an average of $793 total payments, which is, on average, a payback twice the original loan.[96]

ACAA included the **UES "Cash Payments Agents" webpage**[97] in its Testimony that shows ACE Cash Express locations at

- Bullhead City,
- Camp Verde,
- Chino Valley,
- Cottonwood,
- Golden Valley ($1.00 fee)
- Kingman ($1.00 fee),
- Lake Havasu City,
- 3 in Nogales (2 with $1.00 fees),
- Prescott and
- Prescott Valley.

Other billing agents include Ozark "Advanced Quick Cash" in Flagstaff, with other non-payday loan payment agents in Winslow, Show Low, and Sedona.[98]

(c) **Magruder** Initial Brief and subsequent information below discussed these concerns;

a. Additional "connect" charges. Based on UNS Gas Initial Brief, there are two open issues (1) elimination of the Incremental Contribution Study (ICS) and (2) mandatory costs for excess flow valves. During the hearings I presented personal information concerning an earlier ICS when I purchased Magruder home over ten years ago. I never recovered any of Magruder "contribution." There are two classes of ICS-customers, namely, individuals or subdivision contractors. Individuals maybe "infilling" between other residences or making short line additions. Individuals have a much lower probability of seeing any of their contributions returned compared to a subdivision builder. Elimination of a contribution return increases overall cost of a residence; almost *de minimus* in a long-term mortgage.

The mandatory excess flow value cost should be recovered from the contractor or new homeowner, when installed. If this value is to be installed in a current ratepayer, then

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[96] *Ibid.* at 34-35.

[97] See http://uesaz.com?Customersvc/PaymentOptions/Agents/asp verified on 13 June 2007, added new entry for Golden Valley.

[98] *Ibid.* at 35.

using a $10.00 per month for 25 months would be reasonable way to incrementally but completely recover this cost, with any interest to be considered in the next rate case.

b. Billing Schedule. Billing schedules in the UNSG Initial Brief[99] do not agree with prior testimony, Table B-2 (next page) or the reworded rules (R&R Sec. 10.C and 11.E).[100] RUCO also has a different interpretation. The Company never responded to Table 2 in various forms in the Magruder Testimonies, Initial Brief or Exhibit M-1 that reports local concerns on first page of the *Arizona Daily Star* about billing schedule changes.

The Due Date is defined at date bill is rendered, or later of (1) postmark date, (2) mailing date, or (3) billing date shown on bill; however the billing date shall not differ from postmark or billing date by more than two days. UNS Gas uses "drive by" automated meter reading equipment reports its meter readings on a real time basis to the Company by wireless communications. Company billing usually has that bill in the mail that day or the following day. There is a week window in which a gas meter is read.

Bills are not due the same date each month, as they depend on when the meter is read. As a result, the Due Date can be on eight (8) or more different monthly dates. This compounds financial planning for those on set pay periods (weekly, semi-monthly, etc.). UNS Gas and UNS Electricity bill due dates are independent. Monthly utility due dates vary from month to month. Most credit card Due Dates are 20 days after mailing; due on same date each month, sometimes 50 or more days after a credit card purchase..

Table B-2 – Changes in Proposed Termination Dates for UNS Customers.[101]

Action**	Notice	Present Policy	Change	Proposed Policy
Day Meter is Read ≈ DUE DATE	Bill	15 Days after **Due Date**	**5 days earlier**	10 days after Bill is **Due Date**
Penalty Charge Starts (Assessed)	None	15 Days after **Due Date**	**5 days earlier**	10 days after **Due Date**
Bill is **Past Due** (and Delinquent)	None	No payment within 30 days after **Due Date**	**15 days earlier**	15 days after **Due Date**
Suspension of Service Notice/ **Termination Notice**	Written notice by 1st Class Mail	No payment within 30 days after **Due Date**	**15 days earlier**	No payment within 15 days after **Due Date**
		And 10 days prior to **Termination Date****	**20 days earlier**	And 5 days prior to Termination Date**
Earliest Service can be Terminated = TERMINATION DATE	None	No payment within 40 days of **Due Date**	**20 days earlier**	No payment within 20 days of **Due Date**

* Normally within 1 day of the gas meter being read that can vary by 8 or more monthly dates between billings.
** A bankruptcy court may require a more stringent schedule.

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99 UNSG Initial Brief, at 60.
100 Magruder Initial Brief, Table 4, at 31
101 This table was derived to understand these R&R sections. No simple timeline is shown the R&R and definitions are inconsistent. It is very difficult to understand this procedure.

c. Predatory Loan and Check Cashing Facilities as Bill Payment Agents.

The implementation of this reduced billing schedule, when coupled with the Company emphasis on using predatory loan and check cashing facilities as bill payment agents, has caused considerable angst by TEP and Southwest Gas customers locally. Enclosure (1) provides a recent *Tucson Citizen* editorial on this issue. Our Arizona State Legislative representative, Marian McClure has tired to get a bill through the legislature to reduce the impact of these "agents", sometimes on all four-corners of the same intersection.

The Magruder Initial Brief stated:

> "Any reliance of co-located payday and expensive check cashing facilities where utility bills are paid in cash [required by UNS Gas] is an unethical temptation at three locations designated by the Company in Nogales, Santa Cruz County, the smallest Arizona county, where 24.5% of our population lives below the poverty line."[102]

The National Consumer Law Center published *Utilities and Payday Lenders: Convenient Payments, Killer Loans* this June.[103] Enclosure (2) provides a copy of the Recommendations from this report on utilities relationships with predatory lenders.

d. Revised Billing Statement. The Magruder Initial Brief supported the oral testimony on this issue. Fourteen suggestions were recommended in the Initial Brief to improve readability and understandability of all elements necessary for effective compliance using this monthly statement and communications media from the Company.

e. Publication of the UNS Gas Rules and Regulations. As was clearly demonstrated in the Magruder Testimonies, the complexity and wording is required to be simplified into "plain" legally-compliant English, at eight-grade level or lower, because 19.4% of the adults in Santa Cruz County have less than ninth grade reading level.[104]

(3) Final Recommendations for resolution of these issues.

a. Additional "connect" charges. It is recommended that

1. The Incremental Contribution Study (ICS) process be eliminated in the R&Rs and tariffs so that each individual and builder/developer pays for all gas lines and

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[102] Magruder Initial Brief, at 36.

[103] Although this document was issued after the hearings, its data are current and is readily available at www.consumerlaw.com ACAA Executive Director Cynthia Zwick is acknowledged in assisting in the preparation of this excellent document.

[104] Magruder Initial Brief, at 35.

2. All customers requiring the mandated excess flow valves have the first $250 cost amortized over the first 25 months after installation with any additional costs to be considered at the next rate case and
3. The five UNS Gas recommended "connect" charge changes be approved.[105]

b. Billing Schedule. It is recommended that:

1. The proposed billing changes in payment schedules be denied in R&R Sec. 10.C and
2. If the new billing schedule changes are not denied, then the ACC Staff's recommendation for a six month delay be imposed under the following conditions:
   i. The notice of this change be included in a minimum of three different billing notices to customers before implementation and
   ii. This notice be published at least three times in local newspapers and
   iii. This notice be in "plain" English/Spanish with graphics to facilitate understanding and include the required post-termination process, e.g., the actual amount of the required deposit, that is, the two-highest bills in the previous twelve months.
3. All future UNS Gas bills have printed in **bold** with the actual calendar dates for
   (1) BILL DUE DATE,
   (2) LATE PAYMENT PENALTY START DATE, and
   (3) SERVICE TERMINATION DATE FOR NONPAYMENT.
4. The proposed change to R&R Sec. 11.B.1.d be denied and the original version remain as presently stated for "Terminations Without Notification".

c. Predatory Loan and Check Cashing Facilities as Bill Payment Agents. It is recommended that:

1. Because this Company relies on payday loan/check cashing facilities, it is ill-serving its customers. New bill payment agents **shall** be found to replace all payday loan/check cashing facilities within the three months, of if not, then the Company **shall** be directed to consider new incentives for bill payment agents, and, if payday loan/check cashing facilities are not been replaced within **six** months, a Company employee **shall** be on-site during designated days each week at each customer town or city to receive bill payments in any legal form at no charge to customers and

[105] UNS Gas Initial Brief, at 58 (all three bullets) and 59 (first two bullets).

2. All charges to UNS customers for using a credit or debit card **shall** be eliminated when paying by phone (as a service provided by this public service company and at company expense, if any) and
3. The ACC will open a "generic" docket to consider the seven recommendations from the National Consumer Law Center, from enclosure (2) within two months, slightly reworded, to match the situation in Arizona:
   (i) The ACC **shall** prohibit all Arizona public service companies (utilities) or their agents from entering into arrangements to pay for bill collection services from financial service companies or other lenders that lend money at exorbitant rates, defined as when an annual percentage rate is above 36 percent.
   (ii) The ACC **shall** require all utilities with over 750 customers, to maintain company-operated and staffed service centers, including counters for in-person bill payments using cash, at locations convenient for customers throughout the utility service area, at a minimum of one day per week.
   (iii) The ACC will allow utilities to sign contracts for bill payment services at additional locations that enhance convenience for customers but only with supermarkets, drug stores, convenience stores, other retail outlets, community groups, banks or other financial service provides that do not lend money at exorbitant rates.
   (iv) The ACC **shall** require all utilities to verify with the ACC the eligibility of all retail service providers to act as bill payment agents. Utilities **shall** be required to verify that all authorized or unauthorized bill payment agents from whom the utilities accept payments do not hold ACC business or other licenses that allow them to lend money at exorbitant rates.
   (v) When a utility accepts payments from third parties that offer bill payment services to customers but have no contracts with utilities, the ACC **shall** require utilities to receive from those agents certifications that they have charged customers no more than a nominal amount, not to exceed $1.00 or 1 percent, whichever is lower, for bill payment, and that those customers have NOT been solicited to take out loans.
   (vi) The utilities should only be allowed to close down company operated and staffed service centers if they can demonstrate to the Commission that the cost of those centers would put an unreasonable burden on ratepayers.
   (vii) All Arizona laws and ACC financial service regulations should prohibit lenders who collect utility bill payments from promoting or soliciting lending services before, during or after the transaction, and from lending money at exorbitant rates for use in utility bill payments. (Not an UNS Gas action)

d. Revised Billing Statement. It is recommended that

1. The billing statement reformatting suggestions be considered and re-designed to a user-friendly format and
2. A new billing format shall be submitted to all parties within 30-days for comment and review prior to implementation and
3. Any reference to payday loan or check cashing bill payment agents shall be deleted, unless certified to not charge exorbitant rates in accordance with recommendation c.3.v above.

e. Publication of the UNS Gas Rules and Regulations. It is recommended that:

1. The Company publish a new reader-friendly, plain English UNS Gas Rules and Regulations after review and approval by the ACC Staff, and
2. A Spanish-version of the R&Rs be approved by the ACC Staff within the next six months and kept current with the English version and
3. As a minimum, ALL customers will receive a copy or R&R sections shown in Table B-3:

END QUOTE

Table B-3. Minimum Distribution Requirements of the UNS Electric R&Rs [changed from UNS Gas version]

Section	Present Customer	New Customer	Builders or Contractors	When Provided (note 1)
1. Applicability of Rules and Regulations and Descriptions of Service	Yes	Yes	Yes	Within 30 days
2. Definitions	Yes	Yes	Yes	Within 30 days
3. Establishment of Service	If applicable	Yes	Yes	When applying for service
4. Minimum Customer Information Requirements	Yes	Yes	Yes	Within 30 days
5. Master Metering	No	No	Yes	When applying for service
6. Service Lines and Establishments	No	No	Yes	When applying for service
7. Provision of Service	Yes	Yes	No	Within 30 days
8. Characteristics of Service – Voltage, Frequency, and Phase	Yes	Yes	Yes	Within 30 days
9. Line Extensions	No	If applicable	Yes	When applying for service
10. Meter Reading	Yes	Yes	No	Within 30 days
11. Billing and Collection	Yes	Yes	No	Within 30 days
12. Termination of Service	Yes	Yes	No	Within 30 days
13. Administrative and Hearing Requirements	Yes	Yes	If applicable	Within 30 days
14. Statement of Additional Charges	Yes	Yes	Yes	Within 30 days
15. Curtailment Procedures	Yes	Yes	No	Within 30 days

Note 1. "Within 30 days" means a copy of this section shall be provided to the designated receiver within 30 days after approval of the Rules and Regulation section or whenever this section is updated within 30 days or when applying for service.

Exhibit B, Enclosure (1)

"Utilities Send Poor Into The Lion's Den – Tucson Electric Power, SW Gas Direct People Who Need To Pay Their Bills Quickly To Payday Lenders"

by
BILLIE STANTON
Tucson Citizen
Published 06.12.2007

If you're so poor or broke that it's tough to pay your utility bills, the last thing you need is a payday loan with interest of 360 percent or more.

But payday lenders are where two utilities send folks who need to pay in cash, quickly, before the gas or electricity is shut off.

Tucson Electric Power Co. and Southwest Gas Corp. say payday lenders are the only widely and conveniently located sites that will take cash payments.

Eddie Basha isn't buying it, and neither am I. His Food City and Bashas' are the only Arizona grocery stores that take cash payments from utility customers. "It's costly to do it, because in the grocery business, everything revolves around labor," Basha says.

Still, it depends on what kind of business you want to run. "It really is, more than anything else, a convenience for the customer," he says. "And whatever way we can best serve our customers, we try to do it."

That's what utilities claim, too. But they're not doing customers any favors by sending them to payday lenders.

Yet utilities nationwide are doing just that, the National Consumer Law Center reported last week. At ACE Cash Express, Tucson's top taker of such payments, **employees' pay is partly based on how many loans** they make, says its federal securities Form 10K.

ACE's Web site invites customers to also pay telephone bills from T-Mobile, Verizon Wireless and Sprint PCS.

But convenience can be costly. A Gallup, N.M., cashier who borrowed $200 to pay her electric bill because "it was so easy to do" wound up paying $510 in fees on the payday loan over six months, The New York Times reported Dec. 23.

Nationwide, **almost 1 in 4 utility bills is paid in person**, says Dennis Smith of Chartwell Inc., an industry research firm.

They're usually **cash**, paid by customers with low incomes and education, and by minorities - all people less likely to have bank accounts, the law center reports. Their communities have limited banking services - unless you count payday lenders, which are ubiquitous in poor neighborhoods.

In 2000, when TEP moved its headquarters to a downtown high-rise without lobby space or convenient parking, it arranged for payments to be taken by check-cashing stores, spokesman Joe Salkowski said.

Arizona legalized payday lending the same year, and check cashers quickly morphed into payday lenders.

TEP, which gets about 5 percent of its payments from this venue, now is seeking different pay stations, Salkowski said. "We work closely with our low-income (people's) advocates, and we've heard the concern they've raised," he said.

Not so Southwest Gas.
It contracts with Western Union to set up payment sites, and 37 percent of its 648 pay stations statewide are payday lenders, spokeswoman Libby Howell said.

Arizona utility customers pay a $1 fee per bill payment for this service.

If people "merely come in to pay their gas bill," Howell said, "we don't want them to be solicited for a loan. However, we've received no customer complaints."

Reminded that unsophisticated poor people are unlikely to complain, Howell merely murmured assent.

Among Southwest Gas pay stations, 33 percent are at Bashas' and Food City, and 11 percent are at small markets and convenience stores.

If some convenience stores take the payments, why not all?
If Bashas' and Food City can, why not all grocery stores? Why not Walgreens stores, which pepper Tucson?

And for customers with checking accounts, why not their bank or credit union?

"How hard would it be?" asked Kelly Griffith, deputy director of the Southwest Center for Economic Integrity.

It's easy for payday lenders, which continue to proliferate in poor neighborhoods in the 38 states that permit them.

These lenders, whose 24,000 U.S. outlets made $40 billion in loans in 2005, cite high risks. The industry, which gave $2.9 million to political campaigns and committees last year, lobbies on the need to protect "consumer choice," "financial rights" and "your control of your money."
Arizona legislators heard those arguments this year when Rep. Marian McClure, R-Tucson, unsuccessfully pushed reforms.

Despite their arguments, though, payday lenders near military bases wreaked such havoc that a federal law enacted last year limits interest to 36 percent on loans to military personnel.

Civilian poor people be damned, evidently.
Utilities' practice of sending poor customers into the lion's den is an outrage.

"Your most vulnerable consumers are the exact folk payday lenders are looking for," Griffith said. "And it's unconscionable."

Tucson Citizen Editorial Board blog: Legislators' shameful behavior
Billie Stanton may be reached at 573-4664 and bstanton@tucsoncitizen.com. [Emphasis added]

Exhibit B, Enclosure (2)

Recommendations for Utility Regulators from

Utilities and Payday Lenders: Convenient Payments, Killer Loans[106]

1. `State regulators should prohibit utilities or their agents from entering into arrangements to pay for bill collection services from financial service companies or other lenders that lend money at exorbitant rates (typically, an annual percentage rate above 36 percent).

2. `State regulators should require utilities to maintain company operated and staffed service centers, including counters for in-person bill payments using cash, at locations convenient for customers throughout utility service territories.

3. `Regulators should allow utilities to sign contracts for bill payment services at additional locations that enhance convenience for customers but only with supermarkets, drug stores, convenience stores, other retail outlets, community groups and banks or other financial service providers that do not lend money at exorbitant rates.

4. `Regulators should require utilities to verify the eligibility of all retail service providers to act as bill payment agents. Utilities should be required to verify that all authorized or unauthorized bill payment agents from whom utilities accept payment do not hold licenses that allow them to lend money at exorbitant rates.

5. `When utilities accept payments from third parties that offer bill payment services to customers but have no contracts with utilities, regulators should require utilities to receive from those agents certifications that they have charged customers no more than a nominal amount (typically, $1 or 1 percent of the amount due, whichever is lower) for bill payment, and that those customers have not been solicited to take out loans.

6. `Utilities should only be allowed to close down company operated and staffed service centers if they can demonstrate that the cost of those centers would put an unreasonable burden on ratepayers.

7. `State and federal laws and financial services regulations should prohibit lenders who collect utility bill payments from promoting or soliciting lending services before, during or after the transaction, and from lending money at exorbitant rates for use in utility bill payments.

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[106] By the National Consumer Law Center, 77 Summer Street, 10th Floor, Boston, MA 02110 www.consumerlaw.org June 2007, at 27-28.

Service List

<u>Original and 17 copies of the foregoing are filed this date with:</u>

Docket Control (13 copies)
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

Tenna Wolfe, Administrative Law Judge (1 copy)
Ernest G. Johnson, Director Utilities Division (1 copy)
Christopher Kempley, Chief Counsel (1 copy)
Maureen Scott, Senior Staff Counsel (1 copy)

<u>Additional Distribution (1 copy each) are filed this date by mail and e-mail:</u>

Michael W. Patten, Attorney representing the Applicant
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<u>Interested Parties (1 copy each) are filed this date by mail:</u>

Santa Cruz County Supervisors:
  Manny Ruiz, Chairman
  Bob Damon, Supervisor
  John Maynard, Supervisor
Louis Parra, Assistant Santa Cruz County Attorney
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Nogales, Arizona 85621-2262

1BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
M-23
Admitted

COMMISSIONERS
Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC.

Docket No. E-04204A-06-0783

Notice and Filing of the
Supplemental Direct Testimony
with Comments
of
Marshall Magruder
12 July 2007

As provided by the Procedural Orders of 1 February 2007, 27 March 2007, and 25 June 2007, herein is the Supplemental Direct Testimony of Marshall Magruder, a Santa Cruz County UNS Electric, Inc. ratepayer.

The Direct Testimony concentrated on several issues including the Demand-Side Management (DSM) which is reviewed herein and a preliminary UNSE DSM Adjustor rate determined, along with other issues, from the Direct Testimony of 28 June 2007. As indicated in the Direct Testimony, responses to earlier data requests had delayed some issues. It was resubmitted on 29 and 30 June, with responses apparently now delayed until approximately 16 or 17 July 2997, which is after submittal of this Supplemental Direct Testimony.

I certify this filing has been mailed to all known and interested parties in the Service List.

Respectfully submitted on this 12th day of July 2007

MARSHALL MAGRUDER

By Marshall Magruder

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SUPPLEMENTAL DIRECT TESTIMONY

OF

MARSHALL MAGRUDER

12 July 2007

In the matter of
the

APPLICATION
OF UNS ELECTRIC, INC.,
FOR THE APPROVAL OF THE
ESTABLISHMENT OF JUST AND REASONABLE
RATES AND CHARGES
DESIGNED TO REALIZE A
REASONABLE RATE OF RETURN ON THE
FAIR VALUE OF THE PROPERTIES OF
UNS ELECTRIC, INC.

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Supplemental Direct Testimony of Marshall Magruder

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SUPPLEMENTAL DIRECT TESTIMONY OF MARSHALL MAGRUDER

PART I – INTRODUCTION

1.1 Introduction.

Q. Why are you filing this supplemental direct testimony?

On or before 28 June 2007, all intervening parties were required to file their Direct Testimony. The Procedural Orders planned a second Direct Testimony to be filed not later than 12 July 2007. Originally, the second testimony was directed to include rate design issues; however, on 25 July 2007, this was changed to include both Direct-Side Management adjustor and Environmental Portfolio Standard surcharge. My filing on 28 June 2007 indicated that my 12 July 2007 Supplemental Direct Testimony would include both UNS Electric costs and expenses to provide reliable electricity in the Santa Cruz service area and the CARES/CARES-M Program issues.

1.2 Summary of Issues and Recommendations.

Q. Can you summarize the issues from your Direct Testimonies?

A. There are several issues of concern that are in my testimonies. I have numbered them for convenience as follows:

Issue 1 – Demand-Side Management (DSM) Program.

Issue 2 – Administrative Issues

Issue 3 – Costs to Improve Electric Reliability in the Santa Cruz service area.

Issue 4 – CARES and CARES-M Tariffs

Issue 5 – Environmental Portfolio Standard (EPS) Surcharge and Renewable Energy Standard and Tariff (REST)

Q. What are your recommendations?

A. My recommendations vary for each issue.

Issue 1 Recommendations – There are different recommendations for each DSM Program.

- Education and Outreach DSM Program (EC/EE). My detailed Recommendations are detailed in my Direct Testimony in paragraph 3.2.f and in 3.2 herein with the cost changes summarized in Table 1 resulting in adding $273,205 to the 2008 Cost Budget for this program, whose title is recommended to be changed to "DSM Education and Training Program."
- Direct Load Control DSM Program (DR). My detailed Recommendations are in paragraph 3.3.f of my Direct Testimony and 3.3 here. In general, there are serious

structural flaws in this program that need resolution prior to consideration for implementation, which delays determination of a realistic 2008 program Cost Budget.

- Low-Income Weatherization DSM Program (EE). My detailed Recommendations are in paragraph 3.4.f of my Direct Testimony and 2008 Cost Budget changes herein delete $5,104 from the proposed budget.
- Residential HVAC Retrofit DSM Program (EE). My detailed Recommendations are in paragraph 3.5.f of my Direct Testimony and 2008 Cost Budget changes herein to delete $27,954 from the proposed budget.
- Shade Tree DSM Program (EC). My detailed Recommendations are in paragraph 3.6.f of my Direct Testimony which recommend removal of this program from the DSM portfolio, thus to delete all funds ($65,000) in the 2008 Cost Budget because overhead costs exceeded customer benefits.
- Commercial Facilities Efficiency DSM Program (EE). My detailed recommendations are in paragraph 3.7.f of my Direct Testimony and the 2008 Cost Budget which expands customer participation and adds $93,289 to the proposed budget.
- The 2008 proposed total DSM Budget recommended is $3.428.000; however, by reducing all programs to 25% while excluding LIW, the recommended cost of the 2008 DSM Program is $934,878 and an DSM Adjustor rates for all customer billing in 2008 is 0.00057966 per kWh as presented in paragraph 3.9 herein.

Issue 2 Recommendations. See Part IV of my Direct Testimony and Part IV herein as there are numerous Administrative recommendations which delete billing schedule changes, eliminate use of predatory loan and check cashing facilities as UNSE Billing Agents, revise the billing statement, and changes to the UNSE Rules and Regulations.

Issue 3 Recommendations. The detailed electricity reliability in Santa Cruz service area recommendations are presented paragraph 5.4 herein which recommend deletion of $15,561,520 from the UNSE rate base for failure to comply with ACC Orders, to require complete and continuous compliance with the City of Nogales and ACC Staff Settlement Agreements, to avoid include expenses performed by Citizens prior to acquisition to be credited to UNSE, to increase access using WAPA transmission lines with significant customer savings when compared to using TEP transmission lines, to be consistent with objective measures for operations, to comply with NERC/WECC reliability for substation data management, to commence realistic actions required for a second transmission line and not just rebuild a single line, and to cease deliberate and untrue "fear ,mongering" about how soon the "lights will go out" in Nogales.

Issue 4 Recommendations. The detailed CARES and CARES-M recommendations are in paragraphs 6.4 and 6.5, with a major concern that life-support equipment for non-CARES-M ratepayers without any backup support during an outage.

Issue 5 Recommendations. The detailed recommendations for transition from EPS to REST are in paragraph 7.4 which require using the sample tariff surcharges within the first billing cycle after approval of this docket, that UNSE submit a detailed plan on how it will get on track to meet all REST requirements by 1 January 2010 as its renewable generation capabilities account for only 0.00646% of its retail sales in 2006, when the EPS standard required 1.05%.

1.3 Recommendations for additional Issues.

Q. Are there additional issues

A. Yes. Other areas of concern, from the Magruder Motion to intervene that may be resolved before or during the testimonial hearings:

a. *Mandatory* Time of Use (TOU) tariffs for new residential and small commercial ratepayers, This should not be a mandatory program and the use of the highest 15 minute period for calculation of the "demand" (that is one-sixteenth of the peak period and one-fourth eighth of the off-peak period) is not reasonable, thus one hour is appropriate.

b. Proposed Purchase Power and Fuel Adjustment Clause (PPFAC) rate structure includes energy losses, which I have requested by not received a response from UNSE. The present 4.95% WAPA and 10.69% energy losses are paid by ratepayers in the PPFAC. The quantification of energy losses from test year results should be presented by UNSE.

c. New purchase power, generation and transmission agreements impacts on ratepayers which have been requested but not received as they are "confidential",

d. Prudency of its *present* DSM Program since the last rate case as there has been very little "bang" for the "bucks" invested in the present DSM Program,

e. Reliability concerns for the single Nogales substation located in the100-year flood plain,

f. Effectiveness of the ACC *Environmental Portfolio Standard* since the last rate case,

g. Implementation of the *Renewable Energy Standard and Tariff* for all rate categories,

h. Potential for any Citizens-UniSource transition of ownership costs to be absorbed by the customers beyond those in the Settlement Agreement, and

i. Potential for UNS Electricity, Inc. ratepayers to pay multiple or imprudent charges to UniSource Energy and its subsidiaries including increases in O&M and G&A.

Some issues have not been addressed at present due to discovery issues but will be included later in these proceedings.

PART II – ISSUES IN THE DIRECT TESTIMONIES

2.1 Summary of Issues

Q. Can you summarize the issues from your Direct Testimonies?

A. There are several issues of concern that are included in my testimonies. I have numbered them for convenience.

Issue 1 – Demand Side Management Programs, see Part III

Issue 2 - Administrative Issues (Billing Schedules, Predatory Loan/Check Cashing Facilities as Billing Agents, Revised Billing Statement, and R&R Publication) in Part IV

Issue 3 – Cost to Improve Electricity Reliability in Santa Cruz County in Part V

Issue 4 - CARES and CARES-M Tariffs in Part VI

Issue 5 – Environmental Portfolio Standard (EPS) Surcharge and Renewable Energy Standard and Tariff (REST) in Part VII

The first and second issues were in the initial Direct Testimony and supplemental testimony is provided herein. The remaining issues are initially being presented here.

2.2 Impact of these Issues on proposed UNS Electric rates or administrative procedures.

Q. Do any of these issues impact overall capital cost or changes in the proposal?

A. Yes. Each issue will have different changes and impacts, if the recommendations are approved. A brief summary of these changes include:

<u>Issue 1 – DSM Programs</u>. The recommended changes impact the scope and expenses proposed for each proposed DSM Program. Based on these changes, then the aggregated summation of the DSM Adjustor necessary for each program will impact the resultant rates for all UNS Electric ratepayers.

<u>Issue 2 – Administrative Issues</u>. The recommended changes impact areas that are not directly related to company's expenses but directly impact the customers.

<u>Issue 3 – Cost to Improve Electricity Reliability in Santa Cruz County</u>. The recommended changes will remove some capital expenses from the test year which impact rate base.

<u>Issue 4 – CARES and CARES-M Tariffs</u>. The recommended changes may have minor impacts on company expenses as additional administrative procedures are proposed.

<u>Issue 5 – EPS and REST Surcharge/Adjustor</u>. The recommended changes include deletion of the EPS Surcharge; implement an interim Renewable Energy Standard and Tariff (REST) and REST Bank until USNE obtains approval of a new REST Surcharge/ Adjustor in a separate case, and for failing to meet the existing EPS Goals.

PART III – ISSUE 1

DEMAND-SIDE MANAGEMENT PROGRAMS

SUPPLEMENTAL

3.1 UNS Electricity Demand-Side Management Programs.

On 13 June 2007, UniSource Energy Services (UES), for UNS Electricity, Inc., filed with the ACC Docket Control a letter[1] that is the basis for my Direct Testimony. Since filing, additional information has come to light which is now included here. In addition, a summary is provided in paragraph 3.8 where each program's DSM Adjustors are derived and a preliminary aggregated DSM Adjustor rate is determined for billing. All changes to any of these DSM programs must be follow through to determine the impact on cost and the resultant DSM Adjustor rate and impacts ratepayer's bills. The initial Direct Testimony used "XXX" for this process, now superseded here.

The Recommendations from my Direct Testimony concern each UNS Electricity DSM Program below that is reviewed and, if applicable, changes[2] discussed below:

a. Education and Outreach Program in 3.2 below
b. Direct Load Control Program in 3.3 below
c. Low-Income Weatherization Program in 3.4 below
d. Residential New Construction Program in 3.5 below
e. Residential HVAC Retrofit Program in 3.6 below
f. Shade Tree Program in 3.7 below
g. Commercial Facilities Efficiency Program in 3.8 below

Each program is independent of the others; however, the Education and Outreach Program is expanded to provide for <u>all</u> the external media exposures, training, and marketing support in all UNSE DSM Programs, as benefits from one program impact other DSM programs and to facilitate centralized DSM training management, courseware development, media campaigns, and to save costs by cross-functional activities by personnel working in this program.

The terms Energy Conservation (EC), Energy Efficiency (EE), and Demand Reduction (DR) remain as defined in the Direct Testimony (in 3.1.1).

In paragraphs 3.2 to 3.8 of the Direct Testimony, each DSM program is discussed in terms of proposed scope, references, requirements, verification, and recommended improvements. This supplemental Direct Testimony uses the same paragraph numbers.

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[1] UNSE letter "Re: UNS Electric, Inc.'s Demand Side Management Program Portfolio Filing, E-04204A-07-_____", hereafter "UNSE DSM Plan (13 June 2007)", at 2.

[2] Changes are preceded by "(NEW)".

3.2 Education and Outreach DSM Program (EC with potential EE), or DSM Education and Training Program.[3]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.2.f:

(1) Add active implementation tools – no changes.

Annual Cost Impact of Recommendation (1): Add $20,000 per year.

(2) Develop into an Energy Efficiency (EE) program' – no changes.

Annual Cost Impact of Recommendation (2): Add $5,000 per year to administratively handle rebates and awards plus rebates initially at $15,000 per year, thus Add $20,000 per year to Program Cost.

This EE program will have Environmental Benefits thus, 2008 to 2012 is estimates are required for 30,000 annual CFL light bulb change rebates (note, probably twice that number will occur due to publicity) in the program for 2008 to 2012:

GHG	Saved in Pounds	GHG	Saved in Pounds	Others	Saved or not generated
CO2	XXXX	SO2	XXX	Water	XXX gallons
NOx	XXX	Ozone	XXX	Mercury	XXX oz

(3) Create an Energy eNewsletter – no change.

Annual Cost Impact of Recommendation (3): Add $20,000 per year.

(4) Expand "Telephone Energy Assistance" – no change.

Annual Cost Impact of Recommendation (4): Add $10,000 per year.

(5) Include builder in the Commercial educational programs – no change.

Annual Cost Impact of Recommendation (5): Add $40,000 per year.

(6) Aggressively pursue achieving and surpassing performance measures.

(a) Feedback Calls from Call Center - No change, cost is included in Recommendation (2)

(b) Active Speaker Program – No change, no cost.

Annual Cost Impact of Recommendation (6b): Add $10,000 per year for travel

(c) Add more Academic Education - No change.

Annual Cost Impact of Recommendation (6c): Add $30,000 per year but REMOVE from DSM funding, as this should be a corporate "out reach program" and remove "Academic Education," estimated at $15,000 per year, thus result is Remove $15,000 in DSM Program, Add $45,000 to outreach, safety training program in corporate overhead expenses.

[3] UNSE DSM Plan (13Jun2007), Attachment 1 – Education and Outreach Program. A new Title "DSM Education and Training Program" has been recommended as a better title for this program.

(d) Increase in use of Energy Advisor – No change, no cost impact.

(e) Increase academic performance measure - No change, no cost, in Recommendation (6c)

(f) Add easy feedback performance measure – No change, no cost impact

(7) Use Energy Advisor to provide customer's TOU information – No change.

Annual Cost Impact of Recommendation (7) – none (should be included)

(8) Ensure Energy Advisor to show customer's account data – No change.

Annual Cost Impact of Recommendation (8) – none (should be included)

(9) English/Spanish language toggle on the Energy Advisor – No change.

Annual Cost Impact of Recommendation (9) – none (should be included)

(10) Change definitions for types of DSM Programs – No Change, but critical if this Program can qualify as an ACC-defined DSM Program.

Annual Cost Impact of Recommendation (10) – none

(11) (NEW) Change the title of this DSM Program to "DSM Education and Training Programs" to eliminate impacts of Recommendation (10) and reduce potential corporate "marketing" or adverting overhead image. Further, this becomes a "critical" DSM program because it will include and coordinate the Education and Training tasks for all other UNSE DSM programs.

(12) (NEW) Additional Costs from DLC DSM Program from para 3.3.

(13) (NEW) Additional Costs from LIW DSM Program (see para 3.4.

(14) (NEW) Additional Costs from Residential New Construction (ESH) Program from para 3.5

(15) (NEW) Additional Costs from Residential HVAC DSM Retrofit Program from para 3.6,

(16) (NEW) Additional Costs from Shade Tree Program from para 3.7.

(17) (NEW) Additional Costs from Commercial Facilities Efficiency DSM Program from 3.8.

(18) (NEW) Total Annual costs of this program, and then divide by the total of a weighted number of monthly customers, so this program's DSM Adjustor can be calculated.

Table 1. Recommended Program Cost Summary for DSM Training and Education Programs for Implementation in 2008.

Sub para above in ( )	Recommendations as numbered above	Additional Cost	Reduced Cost
1	Add Active Implementation tools	$20,000	0
2	Develop in an Energy Efficient Program	$20,000	0
3	Create an Energy eNewsletter	$20,000	0
4	Expand Telephone Energy Assistance	$10,000	0
5	Include Builders in Commercial Education	$40,000	0
6a	Add Feedback Calls when Call Center not busy	0	0
6b	Add Active Speak Program	$10,000	0
6c	Add more Academic Education (note 1)	$30,000	$45,000
6d	Increase use of Energy Advisor	0	0
6e	Increase academic performance measure (in 6c)	0	0
6f	Add easy Feedback Performance Measures	0	0
7	Use Energy Advisor to Provide Customer's TOU info	0	0

Table 1. Recommended Program Cost Summary for DSM Training and Education Programs for Implementation in 2008.

8	Ensure Energy Advisor can show Customer's Account	0	0
9	English/Spanish toggle on Energy Advisor	0	0
10	Change DSM Program Definitions	0	0
11	Change title to "DSM Education and Training Programs	0	0
12	Training & Education Costs for DLC DSM Program	$125,000	0
13	Training & Education Costs for the LIW DSM Program	$2,552	0
14	Training & Education Costs for Residential New Construction Home (ESH) DSM Program	$21,942	0
15	Training & Education Costs for Residential HVAC Retrofit Program	$12,000	0
16	Training & Education Costs for DLC Shade Tree Program	0	0
17	Training & Education Costs for Commercial Facilities DSM Program	$6,711	0
	Total Cost Changes for DSM Education & Training Program	$318,205	$45,000

Note. Additional academic training was recommended, but the three program included are Company outreach programs for safety and understanding, not directly related to DSM, thus recommend that they be removed from DSM funding and added to corporate overhead expenses.

The total Cost Change for this Program is to **Add $273,205** (318,205 – 45,000).

3.3 Direct Load Control (DLC) DSM Program (DR).[4]

There are no changes to the Direct Testimony.

There are no changes to the Direct Testimony Recommendations para 3.3.f, and if included this program, will require restructuring and new cost/benefits derived. Figure 1 shows information about the time of day and when the DLC control actions[5] might occur.

Month \ Time of Day	00-1AM	1-2 AM	2-3 AM	3-4 AM	4-5 AM	5-6 AM	6-7 AM	7-8 AM	8-9 AM	9-10 AM	10 11	11 12	12-1PM	1-2 PM	2-3 PM	3-4 PM	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM	9-10 PM	10-11	11-12
January							P	P	P	P								P	P	P	P			
February							P	P	P	P								P	P	P	P			
March							P	P	P	P								P	P	P	P			
April							P	P	P	P								P	P	P	P			
May													S	S	P	P	P	P	S	S				
June													S	S	P	P	P	P	S	S				
July													S	S	P	P	P	P	S	S				
August													S	S	P	P	P	P	S	S				
September													S	S	P	P	P	P	S	S				
October													S	S	P	P	P	P	S	S				
November							P	P	P	P								P	P	P	P			
December							P	P	P	P								P	P	P	P			

DLC May-Sept

DLC 1 to 8 P.M.

Figure 1. DLC Action Events and Time of Use (TOU). *This figure shows that DLC events will occur between May and September and from 1 PM to 8 PM in the Box with arrows. Peak Hours are shown with P (red), Shoulder with S (yellow), and Off-Peak (green) are blank.*

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4 UNSE DSM Programs (13 June 2007), Attachment 2, "Direct Load Control (DLC) Programs"

5 The months and hours that DLC actions might occur are from UNSE response to Data Request STF 13.32 of 18 June 2007.

Base on the proposed costs in the proposal (until new estimates are available, the training and education costs are estimated to be $125,000 for 2008 (from "Admin/marketing") and $75,000 annually in 2009 to 2012. This reduces the Program Cost to $1,843,000 in 2008.

3.4 Low-Income Weatherization (LIW) DSM Program (EE). [6]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.4.f:

(1) Add Additional Environment Benefits in Reports – no change, no cost impact.

(2) Delete CARES Billing Assistance – no changes, reduce program cost.
Annual Cost Impact of Recommendation (1): Delete $2,552 per year.

(3) Recalculate customer benefits – no change, no cost now, will impact future results.

(4) Recalculate DSM Adjustor – see para. 3.9 below.

(5) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change may have significant cost impact.

Based on a review of the Program Cost, Training costs shown are $2,552, which should be in the DSM Education and Training Program and deleted from the Program Cost which is now $99,896 [$105,000 - $2552 (training) - $2552 (Cares Billing)] for 2008.

3.5 Residential New Construction DSM Program a.k.a. Energy Smart Homes (ESH) (EE). [7]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.5.f:

(1) Reduce recurrent costs – no changes, reduced cost impacts in 2009 to 2012.

(2) Increase participation annual goals – no changes, increased cost impacts in 2009 to 2012.

(3) Calculate DSM Adjustor – see below.

(4) (NEW) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change is now assumed but could have significant cost impact.

Based on a review of the Program Cost, Training costs shown are $21,924 [36,540 (activity labor) – 10,962 (facilities audits) – 3,654 (facilities audits)], which should be in the DSM Education and Training Program, thus deleted from the Program Cost which is now $398,076 [$420,000 - $21,924 (training)] for 2008.

3.6 Residential HVAC Retrofit DSM Program (EE). [8]

There are no changes to the Direct Testimony.

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6 UNSE DSM Programs (13 June 2007), Attachment 3, "Low-Income Weatherization (LIW) Program"
7 UNSE DSM Programs (13 June 2007), Attachment 4, "Residential New Construction Program"
8 UNSE DSM Programs (13 June 2007), Attachment 5, "Residential HVAC Retrofit Program"

The following are estimated cost for Direct Testimony Recommendations in para 3.6.f:

(1) Remove subcontractor, internal marketing (to DSM Education and Training), - No change, reduce program cost by $47,952 [$35,952 (subcontractor) + $12,000 (DSM Ed/Training)] in 2008 and additional recurring expenses should be reduced in 2009 to 2012.

(2) 17 SEER and 18 SEER and heat pump incentives – no change, Add $10,000 for 17/18 and higher SEER ratings which were missing.

(3) Incentives increase as SEER ratings increase – no change, Add $10,000 for additional stepped-up SEER rating level.

(4) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change but may have significant future cost impacts.

Based on a review of the Program Cost, Training costs shown are $12,000, which should be included in the DSM Education and Training Program, thus deleted from the Program Cost which is now $272,046 [$300,000 - $12,000 (training) - $35,954 (Subcontractor) +$10,000 (17/18 SEER, heat pump) + $10,000 (stepped SEER)] for the 2008 program costs.

3.7 Shade Tree DSM Program (EC).[9]

There are no changes to the Direct Testimony.

The following are estimated cost for Direct Testimony Recommendations in para 3.8.f:

(1) Delete Program – no change, save $65,000.

There DSM Adjustor is zero for this program.

3.8 Commercial Facilities Efficiency DSM Program (EE).[10]

There are no changes to the Direct Testimony.

The following are estimated cost for the Direct Cost Recommendations in para 3.7.f:

(1) Delete Program – no change, save $65,000.

There DSM Adjustor is zero for this program.

(1) Contractors as team players – no change, may have loan expenses but should be balanced by interest payment, net is zero.

(2) Proposal evaluations – no change, no cost.

(3) Commission must decide if this DSM Program should recover Lost Net Revenue, and if so, how much – no change may have significant cost impact.

(4) Add more equipment for rebates – no change, no cost impact as the rebates are fixed.

(5) (NEW) Moved training costs of $6,711 [$11,200 (labor) – $3,369 (Facilities Audits) - $1,120 (Facilities Audits)] to DSM Education and Training of builders and contractors.

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[9] UNSE DSM Programs (13 June 2007), Attachment 6, "Shade Tree Program"
[10] UNSE DSM Programs (13 June 2007), Attachment 7, "Commercial Facilities Efficiency Program"

(6) (NEW) Add 10 more participants per year – change program incentives, Add $100,000 without new administrative overhead by improved staff cost-containment efficiencies.

Based on a review of the Program Cost, Training costs shown are $6,711, which should be included in the DSM Education and Training Program, thus deleted from the Program Cost which is now $493,289 [$400,000 - $6,711 (training) + $100,000 (incentives)]

Q. Can you recommend a way to determine the DSM Adjustor?

A. Yes. Each program's DSM Adjustor factor equals the ratio of the Test Year total energy load in kWh[11] divided by the DSM Program Cost for the year. The sum of each DSM Program's DSM Adjustor factor equals the annual DSM Adjustor rate for ratepayers. All ratepayers will be assessed at the same DSM Adjustor rate for the year. Each year, this should be repeated, using the above process, and, after review and approval by the Commission, the next years DSM Adjustor rate implemented for all ratepayers. This process must be clear, verifiable, and transparent.

During each year, USNE will report the details to monitor each DSM Program, the derivation of the program's semi-annual cost, and for the end of the year, the Total DSM Program financial and performance results. If excess DSM revenue is collected from the effective DSM Adjustor, this excess is subtracted from the next year's cost for that DSM Program, before calculating the next year's DSM Adjustor factor.

During the semi-annual DSM program ACC Staff reviews, USNE should be required to report at least the semi-annual cost-to-date for each DSM program and if the cost minus revenue will positive or negative for each program. All excess DSM funds should be expended in the next year's DSM Adjustor process above. If USNE has overspent (negative excess), the ACC Staff should recommend how UNSE will compensate for overspending to the Commission during the Annual DSM Review for a decision.

Further, when any claims for lost revenue are made "the Commission shall determine whether a utility may be allowed to recover lost net revenue"[12] by the Commission during the Annual DSM Review. In addition, the utility will probably reduce its expenses based on the results of various DSM Programs. The reduction must be considered by the Commission during each Annual DSM Review. Any expense savings by the Company should be an important decision factor when the Commission determines the Annual DSM Adjustor rate.

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[11] The Test Year total energy was 1,606,376,387 kWh from UNSE Response to ACC Staff data request STF 13.14.

[12] ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1, Draft Demand-Side Management Rules, R14-2-1709.B which states "The Commission shall determine whether a utility may be allowed to recover lost net revenue."

3.9 DSM Summary of DSM Costs and Recommended DSM Adjustor.

The proposed and recommended 2008 cost for each DSM program with the calculated DSM Adjustor factors for that DSM Program are in Table 2. It also shows the total cost for the USNE DSM Programs and recommended DSM Adjustor for each program.

Table 2. Cost of Proposed and Recommended Cost of UNSE DSM Programs with DSM Adjustor.

DSM Programs for 2008	Proposed		Recommended	
	Program Cost (100%)	**DSM Adjustor[13]**	**Program Cost (100%)**	**DSM Adjustor**
DSM Education and Training (Note 1)	$170,000	0.00010517	$318,205	0.00019809
Direct Load Control DSM Program	1,968,000	0.00122512	1,843,000	0.00114730
Low-Income Weatherization DSM Program	105,000	0.00006536	99,896	0.00006225
Residential New Construction DSM Program	420,000	0.00026146	398,076	0.00024781
Residential HVAC Retrofit DSM Program	300,000	0.00018676	272,046	0.00016935
Shade Tree Program	65,000	0.00004046	0	0.0
Commercial Faculties Efficiency DSM Program	400,000	0.00024901	493,289	0.00030708
Total	$3,428,000	0.00213334	$3,424,512	0.00213188

Note 1. The title of this program was changed, as recommended to ensure DSM funding for ALL Education & Training activites were included in this program.

Note 2. The Proposed and Recommended Program Costs are 100% but the Company has requested only 25% of costs plus 100% of the LIW program for the first year.

If the Proposed 2008 Program was implemented, the 2008 DSM Adjustor rate would be 0.00213334 so UNSE could recapture the total cost of $3,428,000 in the second column.

If the Recommended 2008 Program is implemented the 2008 DSM Adjustor rate would be 0.00213188 so to recapture the total cost of $3,424,512 in the fourth column.

UNSE has requested that the DSM Adjustor the first year program fund 25% of all DSM Programs except the LIW Program is funded at 100% to fund a study and that the DSM Program Adjustor start later.

Using this formula, the Proposed cost for the 2008 DSM Program is **$935,750** [(total/4 + 3xLIW/4)] (857,000+78,750). The Proposed DSM Adjustor rate is **0.00058236** (0.00053333+0.00004902),

The Recommended Cost of the 2008 DSM Program is **$934,878** (856,128 + 78,750). The Proposed Cost of the 2008 DSM Program was $950,000.

The Recommended DSM Adjustor rate for 2008 is **0.00057966** (0.00053297+0.00004669) per kWh. The proposed DSM Adjustor rate was 0.00059 per kWh.[14]

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[13] DSM Adjustor is calculated using same method in the UNSE Response to ACC Staff data request STF 13.14, by dividing cost by the test year adjusted kWh 1,606,376,397.

[14] Direct Testimony of James S. Pignatelli on behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Pignatelli Direct Testimony" at 15.

Part IV – ISSUE 2
ADMINISTRATIVE ISSUES
SUPPLEMENTAL

Q. Are there any changes to this group of administrative Issues?

A. Yes, minor changes. The title has been shortened to Administrative Issues, with the former title now a subtitle. Also, there are several sub-issues, and for clarity, they are identified as follows:

a. Sub-Issue 2.1, Changes in "Connect" Fees

b. Sub-Issue 2.2, Billing Schedules

c. Sub-Issue 2.3, Predatory Loan/Check Cashing Facilities as Billing Agents

d. Sub-Issue 2.4, Revised Billing Statement

e. Sub-Issue 2.5, R&R Publication.

4.1 Supplemental Testimony Changes to these Administrative Issues.

There are no changes except as to my Direct Testimony Exhibit B. In Exhibit B, in addition to those in the Direct Testimony, and supplemental testimony are provided:

<u>Sub-Issue 2.1</u> – Not at issue in this UNSE case

<u>Sub-Issue 2.2 – Billing Schedule</u>. <u>Replace</u> Exhibit B and Table B-2 on this issue with:

UNSE proposal to reduce the time between the Bill Due (when rendered, usually date mailed) and when the bill becomes "Past Due." Fifteen days after a bill becomes Past Due it is Delinquent, the penalty charge starts, and the Termination process begins. The Termination process for Delinquent bills requires 5 days notification by mail before Termination.

a. The Company's proposal is to change the interval from Bill Due to Delinquent from 15 days to 10 days.[15] A review of A.A.R., R14-2-210.C.1 states "All bills for utility services are due and payable no later than 15 days from the date of the bill. Any payment not received within this time-frame shall be considered delinquent and could incur a late payment charge." <u>This change is a unique interpretation of the A.A.R.</u>

b. The Company's proposal is to change the interval from when a Bill becomes Deliquent to the start of the Termination Process from 7 days to 5 days.

c. The Company issues a Suspension of Service Notice 15 days after the bill is rendered. The A.A.R. does not discuss a Suspension of Service Notice, only a Termination Letter.

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[15] Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, 15 December 2006, Exhibit TJF-1, relined page 82, Section 11.C.1, which states. All bills for electric service are due and payable no later than <u>ten (10)</u> days from the date the bill is rendered. Any payment not received within this time frame <u>will</u> be considered past due." [underlined were the changes, "fifteen (15)" and "shall" in original]

If they are the same, the proposed Timeline below for Termination becomes 20 days instead of 25 days, a 12 day reduction from the 37 days after billing to termination.

d. At the earliest, it is possible for a customer to have their service terminated 20 (or 25) days after the Bill is mailed, which can very between 25 and 35 days after prior bill. Within a ten day billing window, and a twenty day schedule, customer financial planning for monthly wage checks becomes very challenging for lower-income ratepayer.

<u>THE PRESENT TIMELINE OF BILLING EVENTS:</u>

Day -1 to 0	Meter is read, reported to the Company (between 25 and 35 days after prior reading)
Day 0	Billing Date, when the bill is rendered (considered when mailed), the Bill is Due
Day 15	(15 days after Due) Bill is Past Due
Day 25	(10 days after Past Due) Bill is Delinquent, Payment Penalty starts
Day 30	Late Penalty (1.5%/month) starts for all account balances 30 days after postmark of account bills
Day 32	(7 days after Delinquent) Termination Process begins
Day 37	(5 days after Termination letter is mailed, Earliest Termination

<u>THE PROPOSED TIMELINE OF BILLING EVENTS:</u>

Day -1 to 0	Meter is read, reported to the Company (between 25 and 35 days after prior reading)
Day 0	Billing Date, when the bill is rendered (considered when mailed), the Bill is Due
Day 10	(10 days after Due) Bill is Past Due
Day 15	(15 days after Due) Bill is Delinquent, Payment Penalty starts and is payable on a monthly basis, Suspension of Notice letter is sent
Day 20	(5 days after Delinquent) Termination Process starts
Day 25	(5 days after Termination Letter mailed), Earliest Termination

It should be noted in Table 3 the A.A.R. is generally inconsistent with respect to utility billing dates as summarized below. A typical credit card timeline is added for a comparison.

Table 3. Comparison between Present and Proposed Billing Schedules.

Utility	Billing Due	Past Due or Delinquent	Termination (days after Past Due)
Electricity	0	+15 days	+5 days after letter
Natural Gas	0	+10 days	+5 days after letter
Water	0	+15 days	+10 days after letter
Telephone	0	+15 days	+7 days after Past
Sewage	0	10 for Past Due	+15 to Start Term. + 5 days after letter
Credit Card	Purchased up to 31 days before	+20 days	Between 21 and 51 days after purchase

It is <u>recommended</u> that:

(1) That Past Due dates conform to the A.A.R., using 15 days after Billing date.

(2) That all proposed billing schedule changes be denied.

Sub-Issue 2.3 - Predatory Loan/Check Cashing Facilities as Billing Agents.

See Exhibit B, which provides the basis, discussion and recommendations to the proposed changes in billing statements. UNSE refers ratepayers to these facilities hired as UNSE billing agents to pay in person by cash "at multiple 'ACE Cash Express Stores' located throughout the UNS Electric service territory."[16] It is not appropriate to use possible predatory loan/check cashing facilities as UNSE billing agents for lower income ratepayers to pay their bills in "cash" since most do not have a bank account and also have to pay a "check-cashing" commission to "cash" their paycheck in order to pay their bill in cash.

No changes in testimony or recommendations from that in Exhibit B are necessary. Two new Enclosures to Exhibit B are in this Supplemental Testimony.

Enclosure B-3 provides the present UNSE Payment Agents for making cash-only bill payments. The UES website lists 12 ACE Cash Express and one QA Quick Cash facilities.[17]

Enclosure B-4 provides how one could pay their bill online with a bank withdrawal or with a credit or debit card with a third-party administration fee of $3.95 per payment.

The Recommendations in Exhibit B remain unchanged: (1) Do not allow payday loan organizations as payment agents and (2) Do not require any fees for online bill payments.[18]

Sub-Issue 2.4 – Revised Billing Statement. See Exhibit B for detailed recommendations to changes proposed to the billing statement sent monthly to UNSE ratepayers. No changes in testimony or recommendations from that in Exhibit B are necessary. There were fourteen recommendations to revise a new billing statement format presented in the UNS Gas Rate Case as found in Exhibit B. Since the billing statements for UNSG and UNSE are very similar, these same detailed recommendations apply. These details will be presented for the record as a Magruder Exhibit during oral testimony.

Sub-Issue 2.5 – R&R Publication. See Exhibit B and recommendations to publish the ACC-approved UNSE Rules and Recommendations (R&R). No changes in testimony or recommendations from that in Exhibit B are necessary. Table B-3 reflects the UNSE R&R Section Titles.

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16 Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, Inc., of 15 December 2007, hereafter as "Ferry Direct Testimony" at 8.

17 See www.uesaz.com/Customersvc/PaymentOptions/Agents.asp (verified 9 July 2007)

18 See https://secure3.i-doxs.net/unisource/OneTime_Add_UniElec.asp?Ac (assessed via UNSE website, verified 9 July 2007)

Part V – ISSUE 3

Costs to Improve Electricity Reliability in the Santa Cruz Service Area

5.1 Reliability Issues in the Santa Cruz Service Area.

Q. Why are Reliability Issues in Santa Cruz Service Area important in this rate case?

A. As a long-term issue, expenses to rectify reliability issues impact the Company's costs and thus will impact rates. This issue is long and needs to be introduced in the context of original problems, ACC reviews and Orders, and compliance.

Q. What are the recent ownership changes of the electric companies in Santa Cruz area?

A. In the 1990's Citizens Utilities Company was renamed Citizens Communications Company Arizona Electric Division (AED)[19] in Santa Cruz service area (and also the Mohave service area). Citizens held the CC&Ns for service in the Santa Cruz River Valley area of Santa Cruz County, from the Pima County line to the Mexican border. Citizens purchased the Nogales Electric Company, who had provided local electricity service in the 1890s, about 1950. Citizens installed the first transmission line between Nogales and Tucson about 1952.

Unfortunately, Citizens initial service was less than desired. Only by a technical error[20] an election for the City of Nogales to municipalize Citizens was overturned during 1953-55.

To the east is Sulfur Valley Springs Rural Cooperative and to the west is TRICO, another rural cooperative. Citizens obtained two DOE Presidential permits to supports a Santa Cruz, small village in Mexico, and to provide an emergency transmission line connection between the two countries which has never been completed nor used.

On 11 August 2003, the purchase of Citizens by UniSource, Inc. was completed and the new public service company, UNS Electric, Inc. combined the organization for the Mohave and Santa Cruz service areas. The Purchase Agreement required Citizens to deliver to UniSource various agreements needed by the Buyer.[21]

Q. How did reliability become such a problem in this area?

A. In 1998 and 1999, there were a series of frequent and long electrical outages in the Santa Cruz service area. These outages were so severe that the City of Nogales filed a Formal

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[19] Hereafter, Citizens.

[20] The technical error was misspelling "Citizens" as "Citizen's" on the bonds required for the City's purchase, which eventually adjudicated to negate the vote to municipalize. Another municipalization attempt occurred failed in the September 2003 election.

[21] Asset Purchase Agreement by and between Citizens Communications Company, as Seller, and UniSource Energy Corporation, as Buyer (hereafter, UniSource-Citizens Purchase Agreement), of 29 December 2002, section 3.5 (Deliveries by Seller) at pages 24-25 net al, found in ACC Docket No. E-01032C-00-0751, et al, which resulted in ACC Decision 66028.

Complaint with the Commission, Nogales cancelled its franchise agreement with Citizens, and demanded actions be taken to improve reliability. After a series of ACC hearings, the City of Nogales and Citizens signed a Settlement Agreement[22] which includes demands on Citizens:

a. To direct payments of $15.00 to all customers in Santa Cruz County (completed)
b. To provide a neutral claims resolution procedure for all customers. (completed)
c. To fund low income relief. (completed)
d. To fund several Santa Cruz County economic-development efforts. (remains open)
e. To fund annual four-year, interest free, scholarship/loans for Santa Cruz County high school graduates that will be forgiven, if the student returns to live and work in the County for two years. (remains open)
f. To improve future electric service and community relations, Citizens and the City will:
   (1) Create a Citizens Advisory Council, (initially resolved but now is open)
   (2) Collaborate to determine the order in which circuits are energized in the event of future transmission-related outages. (presumed closed)
   (3) Develop a mutually acceptable Service Upgrade Plan for submission to the Commission. (remains open)
   (4) Negotiate a mutually acceptable 25-year franchise for Citizens. (completed)

The City also dismissed the Complaint with prejudice. [underlined in original]

In addition to the Citizens-Nogales Agreement, Citizens lost a civil law suit for $2.5 million, most of which $1.9 million was rebated to all its customers during this time period.[23]

Q. Why is this City of Nogales-Citizens Settlement Agreement still important?

A. Because it formed the foundation to improve reliability and quality of service in this area. It established actions required by Citizens, and its successor, UNS Electric. But before we go to other ACC Orders and Agreements, let us look at compliance with the terms of this agreement. As indicated above, some of these Citizens agreements remain open eight years later.

Q. Why would action required by an ACC Order for Citizens pertain to UNS Electric?

A. When UNS Electric, Inc. acquired Citizens, all Citizens obligations should have automatically been novated directly to UNSE.[24] Incomplete actions required by ACC Order Nos. 61793, 62011, and others are on going or not completed. The remaining actions are discussed next.

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[22] The "Citizens-City of Nogales Settlement Agreement" was approved in ACC Decision No. 61793 of 29 June 1999 for Docket No. E-01032B-98-0621 without change which also "ordered that Citizens Utilities Company shall provide a planned service date and required a cost benefit analysis for the system components of a second transmission line be included in its Plan of Action" at page 4, at 11 to 14.

[23] *Chilcote versus Citizens Utilities.*

Q. What "Santa Cruz Economic Development" efforts remained?

A. In addition to provision of "seed" money, Citizens was to work with the Citizens Advisory Council and an Economic Development Roundtable to "develop new-business incentive-rate tarries intended to attack new business to Santa Cruz County" and to "evaluate appropriate changes to existing commercial and industrial tariffs" and to file resulting changes with the ACC for approval.

<u>This has NOT been accomplished</u>, as the existing business electric rates discouraged bussiness. This was a major objection I had in my filings in the Purchase Power and Fuel Adjustment Clause case in Docket No. E-01032C-00-0751. Further, Mohave County Economic Development personnel also objected to these high business and commercial tariffs during those hearings.[25]

Q. What is the status of the annual "Funding Four-Year Scholarship/Loans"?

A. A review of the annual scholarships sections in recent *Nogales International* newspapers have not listed any scholarships from UniSource, UES or UNS Electric, Inc. This Settlement Agreement, in Article 9, stated "Each year, the program will select..."[26] which is clear this is an annual scholarship program. <u>This has NOT been continued, may not ever have started.</u> I have an open data requests on this to UNSE, which has not responded as of this submission.

Q. What has been done with the "Create a Citizens Advisory Council" obligation?

A. This was initially established to "discuss electric and gas service issues, upcoming Commission filings and other topics of mutual interest such as electric deregulation and demand-side management."[27] The last meeting of the CAC was in September 2000, just after TEP and Citizens agreed to work together on the 345 kV transmission project. <u>This has NOT been continued, "Public participation" was unilaterally stopped, without Commission approval and unilaterally by the utility.</u>"[28] In response to a Magruder Data Request "UNSE Electric has not

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[24] UniSource-Citizens Purchase Agreement, *op cit.*

[25] Docket No. E-01032C-00-0751, In the Matter of the Application of the Arizona Electric Division of Citizens Communications Company to Change the Current Purchased Power and Fuel Adjustment Clause Rate, to Establish a new Purchased Power and Fuel Adjustment Clause Bank, and to Request Approval Guidelines for the Recovery and Costs Incurred in Connection with Energy Risk Management Initiatives, the "Marshall Magruder Brief," of 15 May 2003, page 3 at 27 to 30, page 7 at 9 to 13, et al. It should be noted, the above docket was merged with two other docket Nos. G-01032A-00-0598 and E-01933A-02-0914.

[26] City of Nogales-Citizens Settlement Agreement, p. 7, Article 9, Educational Support.

[27] *Ibid.* p. 4, Article 3, Citizens Advisory Council.

[28] Citizens in a Docket No E-01032B-98-0621 filing "Settlement Agreement Between the City of Nogales, Arizona, and Citizens Utilities Company" of 12 February 1999, stated "The CAC will meet regularly (as agreed by its members) to discuss electric and gas service issues, upcoming Commission filings and other topics of mutual interest such as electric deregulation and <u>demand-side management</u>. The CAC will also assist Citizens by evaluating alternatives for long-term electric reliability in Santa Cruz County, such as a

held any public meetings regarding the [this] filing."[29] A press release "sent to Santa Cruz County Manager and Nogales City Manager" and one billing stuffer are inadequate for informing the ratepayers about the significant changes in this application.[30] Even though some meetings where held in Mohave County, the Time of Use (TOU) provision was only mentioned "generally as an incentive to shift load off of UNS Electric' peak load times." The Purchase Power and Fuel Adjuster [sic, Adjustment] Clause was not discussed."[31]

Q. What about "Determine the Order of Circuits after Transmission Outages"?

A. This task was established to promote collaboration by Citizens with the City to determine the initial order for circuits to be re-energized due to an outage of WAPA or 115 kV transmission lines. The local turbines would be used. This appears to have been accomplished by changes in tie lines so that all emergency circuits were energized first. This task stated "in collaboration with the CAC, Citizens will evaluate whether to keep generation in spinning reserve during inclement weather."[32] As there have been no CAC meetings since September 2000, unilaterally, UES requested and obtained ACC approval in 2004-05 not to have spinning reserve (turbines in standby) during storms.[33] Any collaboration with the CAC on the issue of having the local turbines in "standby" or spinning reserves was not complied as agreed.

Q. What about "Develop a Mutually Acceptable Service Upgrade Plan"?

A. This task was for Citizens to file a Service Upgrade Plan for comments by both the City and the Residential Utility Consumers Office (RUCO) including Citizens funding RUCO for this task. This plan was filed and incorporated into the ACC Staff Settlement Agreement months before ACC Decision No. 62011 on 2 November 1999 was decided when the Commission approved the Citizens Plan of Action agreements with the ACC Staff. No collaboration with RUCO occurred in the development of this plan.

Q. What about a "Mutually Acceptable Franchise Agreement"?

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second transmission line, and recommend a preferred alternative to Citizens and the Commission" at page 3, paragraph 3. The actions indicated by the last sentence were never accomplished by the CAC.

29 UNSE response to Magruder data request MM DR 1.8a.

30 UNSE response to Magruder data request MM DR 1.8b.

31 UNSE response to Magruder data request MM DR 1.8c.

32 Nogales-Citizens Settlement Agreement, p. 4, Article 4, Back-up Generation.

33 See ACC Order No. 67151 of 3 August 2004 that waived the $30,000 penalty for failing to have a second transmission line in service by 31 December 2003.

A. This was not accomplished by Citizens but added as a Condition to the UniSource Acquisition of Citizens Settlement Agreement.[34] A Franchise Agreement was approved in the general election in September 2004.[35]

Q. You mentioned an ACC Staff- Citizens Settlement Agreement, what is this about?

A. This ACC Staff-Settlement Agreement is in the Citizens "Supplement to Santa Cruz Electric Division Transmission Alternatives and Plan of Action"[36] which was filed to comply with ACC Order No. 61383.[37] UNSE's witness Mr. Beck Direct Testimony stated:

> "Prior to UNS Electric's acquisition of the system from Citizens, there were significant concerns about the reliability of electric service in Santa Cruz County. As a result of these concerns and a Commission proceeding, Staff and Citizens filed a Settlement Agreement in August 1999 the committed Citizens to a Plan of Action. The Settlement Agreement was subsequently approved by the Commission in Decision No. 62011 (November 2, 1999). Under the Plan of Action, Citizens had:
>
> - Added a new system (sync-check relay) to synchronize Citizens generation units at Valencia Power Plant with Western Area Power Administration's ("WAPA") transmission system;
> - Installed a new 115kV switching station at Nogales Tap Station to convert the interconnection between Citizens and WAPA from a simple tap to a three breaker ring bus;
> - Replaced selected structures and components on the existing 115kV line;
> - Pursued a second transmission source into the service area."[38]

This Supplement Agreement listed and required many reliability improvements that impact all elements of the Santa Cruz electrical system. The Settlement Agreement also required a second transmission line and other improvements, not dependent on the Second Transmission Line, and schedules and Gantt chart showing completion by the end of 2003. [39]

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[34] In ACC Docket Nos. E-01032C-00-0751, G-01032A-00-0598, E-01933A-02-0914, E-01032C-02-0914 and G-01032A-02-0914, the resultant joint ACC Staff-Citizens Settlement Agreement (hereafter Staff-Citizens SA), at pages 7 to 8, paragraphs 8 and 9, required that all franchise agreements be provided to the Commission within 365 days of closing, which occurred on 11 February 2003. Thus, based on the following footnote, this franchise was approved more that 365 days later.

[35] On 2 November 2003, the 55.6% of City of Nogales voters approved the UNSE franchise and 57.19% voted to approve the UNSG franchise. These are not large majorities.

[36] Direct Testimony by Edmond A. Beck on Behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Beck Direct Testimony", at 4,

[37] This "supplement" is also in TEP and UES filing in Docket No. E-01032A-99-0401, "Notice of Filing Response to Commission Questions and Updated Outage Response Plan for Santa Cruz County" filed on 9 February 2004, in the first exhibit (sic), filed by Citizens under Docket No. E-01032A-98-0611, et al, "Supplement to Santa Cruz Electric Division Transmission Alternatives and Plan of Action," filed on 7 May 1999. In addition, on 15 April 1999, Citizens filed the "Transmission Alternatives and Plan of Action" (written by Citizen's consultants, Power Engineers and Dames & Moore) to which the "supplement" amplified.

[38] Beck Direct Testimony at 4 and 5.

[39] This filing with for the Citizens "Supplemental Plan" does not have numbered pages. The Adobe PDF version, filed in TEP's 9 February 2004 in Docket No. E-01032A-99-0401 is paginated by the PDF program. These pages numbers are used for reference purposes as "Citizens Supplemental Plan, PDF page X".

The Settlement Agreement has many ACC-approved commitments by Citizens, now assumed by its successor, UNSE. A Citizens "Plan of Action" dated April 15, 1999 and updated on 7 May 1999 and 13 July 1999 addressed service quality issues in ACC Decisions No. 61383 and 61793.[40] These

a. Require Citizens to construct a second transmission line.[41]

b. State Citizens "will endeavor to place the second transmission line in service by four years after the date of a Commission Order approving this Settlement Agreement."[42] That date was November 2, 2003.

c. State "If an Environmental Impact Statement is not needed, Citizens [UNS Electricity] will endeavor to achieve an in-service date of 39 months after the date of a Commission Order approving this Settlement Agreement."[43] That is an in-service date of February 2, 2003 and would itself have been subject to the Delay Penalties.

d. Require USNE to "fulfill Citizens' obligations for the second transmission line as a condition of the Commission's approval of the sale."[44]

e. Order Citizens (USNE)

> "to proceed with planning, permitting, and constructing a second transmission line to serve its Santa Cruz Electric Division Customers, subject to the siting process and schedule that Citizens filed on July 13th, 1999. Presently the preferred alternative is the Bicknell-Valencia route, but the parties recognize that completion of transmission studies and environmental approvals may identify another route as the route to be constructed."[45] [Note: Bicknell-Valencia did not require an EIS.]

f. The Settlement Agreement has a "Delay Penalties" clause which reads:

"4. Delay Penalties.

a. If the second transmission line is not placed in service by December 31, 2003, then Citizens will owe a penalty of $30,000 per month for each full month of delay after December 31, 2003. This penalty represents liquidated damages for Citizens' failure to fulfil its obligations under this Agreement and will be for the benefit of Citizens' Arizona electric customers. Citizens will compute and owe the penalty no later than 30 days after the transmission line's actual in-service date. If the transmission line is not in service by December 31, 2003, then on January 31, 2005, Citizens will compute and owe the accrued penalty for the previous year. Citizens' obligation will then continue in a like manner on each January 31, thereafter, until the transmission line is actually in service. In the year the transmission line is actually placed in service, Citizens will then compute and owe the penalty no later than 30 days after the transmission line's actual in-service date.

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40 ACC Staff-Citizens Settlement Agreement, 1/17-18.
41 *Ibid.*, 1-15-16.
42 *Ibid.*, 1-27-29.
43 *Ibid.*, 29/2 to 2/1-2.
44 *Ibid.*, 3/5-8.
45 *Ibid.*, 1/20-25.

b. No later than each date in the preceding paragraph by which Citizens is to compute and owe a penalty, Citizens will file with the Commission its proposal as to which of Citizens' electric customers will receive the benefit of the penalty amount and how the benefit will be distributed (e.g., bill credit, credit to PPFAC bank balance, refund, or other methodology). The Commission will then determine by Order the appropriate recipients and distribution methodology.

c. If Citizens believes that circumstances beyond its reasonable control (such as unavoidable delay in obtaining a Certificate of Environmental Compatibility, court injunction, or other good cause) are responsible for the delay, Citizens may apply – no later than December 31, 2003 – with the Commission to delay the December 31, 2003, date or to waive the penalty. If Citizens makes such a filing, Staff and any other, interested party may file a response either supporting, not objecting to, or objecting to Citizens' application. The Commission will then determine the appropriate relief, if any."[46]

Q. What did this Staff-Citizens Agreement say about a second transmission line?

A. It had seven requirements for the second transmission line that include:

a. Proposed Deadline for Implementation. The earliest deadline indicated was February 2002; however, an in-service date of 2003 was indicated.[47]

b. Cost-Benefit Analysis. A detailed Cost-Benefit Analysis was filed by Citizens. The Supplement has preliminary cost estimates for the four potential interconnections and routes in Table 4.

Table 4 – *Transmission Alternatives Considered by Citizens and Cost Estimates.*
This Citizens assessment provided four 115 kV alternatives for the Second Transmission Line to the Nogales Valencia Substation.

Interconnection With	From Substation	To Substation	Initial Cost Estimates	Cost in Supplement[48]
AEPCO	Bicknell	Valencia	$10.6 million	$ 21.0 million
AEPCO	Sierra Vista	Valencia	$11.6 million	$ 20.9 million
AEPCO	Pantano	Valencia	$14.0 million	$ 23.0 million
TEP	Vail	Valencia	$16.25 million	$ 27.0 million

c. Alternatives. The four 115 kV transmission line routes above were identified, with the Bicknell being the preferred with respect to system performance and cost and "this

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46 *Ibid.,* 4/3 to 5/4. The ACC Staff Direct Testimony of 20 August 1999 stated "The [ACC Staff-Citizens] Agreement also establishes a framework for delay penalties applicable for Citizens failure to perform in accordance with their proposed schedule." Page 2, lines 3 and 4.

47 In Citizens Supplemental Plan, PDF pages 24, 25, and 36 to 39. On PDF page 39, the Citizens Data Response to Staff's First Set of Data Requests, 28 January 1999, Date Request No. RF-2, the ACC Staff asked how the year 2003 was selected; the earliest possible in-service date and what could prevent Citizens from installing this line prior to 2003. In ACC Staff Supplemental Testimony of 16 July 1999, the "Staff is concerned about schedule creep … this seems to indicate that Citizens has just recently become serious about planning for and constructing a second transmission line, despite the report of September 1971 [which indicated the reliability need]. Staff believes the delay in starting the process and filling the associated reports has been excessive and unreasonable." At page 8 lines 7 to 14.

48 These costs were referenced in the Joint TEP-Citizens CEC Application for a 345 kV line as the maximum Citizens would be required to pay under all scenarios' for a second transmission line to meet the ACC-mandate in ACC Order No. 62011. TEP managed the construction and would absorb all other costs.

interconnection is the best technically, is the lowest capital cost, and the route generally crosses terrain that has other linear developments, such as natural gas pipe line and interstate highway".[49]

d. Power Flow Studies. Preliminary power flow studies completed by AEPCO supported the Bicknell alternative. Further, the "second 115 kV line would need to operate in parallel with WAPA's transmission system."[50] TEP did not conduct any power flow studies for its proposed "Vail" interconnection.[51]

e. Environmental. Of these four alternatives, the Bicknell and Vail alternatives presented fewer environmental permitting problems; however, a TEP Vail alternative would transverse more highly-developed areas. The other two alternatives would follow AZ Highway 82 is far more environmentally sensitive.[52]

f. Transmission Service Costs. The

> "addition of a second transmission line interconnected to a system other than WAPA will require an interconnection agreement and potentially, a transmission service contract with the transmission owner. Any transmission service costs are expected to be in addition to those presently incurred for use of the WAPA's system."[53]

Thus, any system, other than WAPA's, has higher rates for the Santa Cruz customers.

g. Selection of the Preferred Plan. Citizens with Power Engineers and Dames & Moore, consulting firms, developed the work plan; environmental characteristics for each alternative; outlined the required steps; and projected a permitting, design and construction schedules for the second transmission line. This plan was for "planning with local, state, and federal agencies to develop the information necessary for applying for a Certificate of Environmental Compatibility" with the Line Siting Committee the Transmission Alternatives and Plan of Action Report.[54]

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[49] In Citizens Supplemental Plan, PDF page 25.

[50] *Ibid.* PDF pages 29 and 37. This point is very important. Almost all power consumed by Citizens is "firm" delivery, which means the supplier MUST always provide this power. In general, when the same suppler provides transmission in "parallel" for two of its interconnections, the user will only have to pay for electricity that is consumed and transmission charges for what is transmitted, one pays for power once. If a second, independent (a different) provider transmits power, the "second" power supplier must also be paid, even if NO power is consumed, one pays for power twice. Thus, one supplier is less costly for ratepayers when compared to two suppliers. WAPA is the transmission supplier for both Citizens and AEPCO but is not for TEP. Thus, as early as January 1999, this principle was known and understood by Citizens in its own report.

[51] In Citizens Supplemental, PDF page 37, "TEP has not completed power flow cases for any potential interconnection."

[52] *Ibid.* PDF page 30.

[53] *Ibid.*

[54] *Ibid.* This report was filed with the Commission on 15 April 1999.

Q. And what are the other (non-second transmission line) reliability improvements in the Citizens Plan?

A. Yes, these involved many projects for above ground pole replacements, below ground cable replacements, power supply improvements, and several substation improvements including Nogales Tap, SCADA and communications improvements. The Citizens plan extended from 1999 through 2003, with completion of a second transmission line and reliability improvements by the end of 2003. All were important. Each project directly impacted customer's reliability.

Q. Were all of these ACC-approved reliability improvements implemented as planned?

A. Let us look at each because, as some of these items remain to be completed and others were completed by Citizens or UNS Electric. Some are visible, such as utility pole and underground cable replacements.

Q. What is the status of the above ground pole replacements compared to the plan?

A. The Citizens plan presented a ground pole replacement plan for each year, from 1999 through 2003 to replace 3,060 poles that "have reached the end of their life cycle."[55] Twenty different pole replacement projects were approved at a total expenditure of $9,155,000 with $4,320,000 to be spent in 1999 and $1,265,000 in 2000. In 2001, 2002, and 2003 the expenditures for pole replacements was level at $1,275,000 each year. A "progress to date" in 15 April 1999,[56] shows that 634 poles had been replaced for the estimated 616 as of this report. Table 5 below shows the plan for replacing these above ground poles.[57] The early results of this program were impressive; however, when it was known Citizens was "for sale" it appears this work effort was reduced or stopped.

The important unanswered question in this UNSE Rate case is how many of the 3,080 above-ground utility poles approved by the Commission in the Citizens-ACC Staff Agreement have been actually replaced? UNSE should have finished these twenty projects by the end of 2003 as shown in Table 5; however, this has not been verified as completed work.

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[55] *Ibid.* PDF page 52.

[56] I tried to obtain an update with data requests this docket but was refused so far. In an earlier ACC Docket No E-01032A-99-0401 without success as I was told to pursue this issue in the "next rate case." Please see Magruder Testimony of 8 July 2005 in that docket, Appendix E.2, pages 135 to 136 for the utility pole replacement programs. I know these areas and by observation, many "old" poles remain and the new poles are obvious, many being metal ones replaced by Citizens are a real improvement and should improve distribution reliability.

[57] In Citizens Supplemental Plan, PDF pages 26, 41, 43, 45, and 52.

Table 5 – Above Ground Pole Replacement Plan. Twenty different ground pole replacement projects were to be accomplished by 31 December 2003 at a cost of $9.155 million.

Proj. ID	Pole Replacement Project	Total No of Poles	1999 Est. No.	Poles to date	1999 ($)	2000 ($)	2001 ($)	2002 ($)	2003 ($)
1	Nogales Wash area	75	75	26	300,000	0	0	0	0
2	Nogales West north area	75	15	28	90,000	30,000	30,000	30,000	30,000
3	Reconductor Mariposa Industrial Park	75	1	1	90,000	75,000	0	0	0
4	Downtown Southeast	300	60	74	360,000	120,000	120,000	120,000	120,000
5	Downtown Northwest	300	60	115	360,000	120,000	120,000	120,000	120,000
6	Downtown Southwest	500	100	91	474,000	200,000	200,000	200,000	200,000
7	Downtown Northeast	300	60	20	360,000	120,000	120,000	120,000	120,000
8	Beatus Estates	150	0	0	180,000	60,000	60,000	60,000	60,000
9	Valle Verde	150	30	106	180,000	60,000	60,000	60,000	60,000
10	Chula Vista	50	2	0	60,000	20,000	20,000	20,000	20,000
11	Activate Circuit 6242	100	0	0	180,000	60,000	60,000	60,000	60,000
12	Circuit 6241	50	10	0	60,000	20,000	20,000	20,000	20,000
13	Meadow Hills North	75	15	0	90,000	30,000	30,000	30,000	30,000
14	Meadow Hills South	75	15	0	90,000	30,000	30,000	30,000	30,000
15	Transmission Line	20	2	0	320,000	0	0	0	0
16	Highway 82	250	60	148	275,000	120,000	120,000	120,000	120,000
17	Old Tucson Road	10	10	9	25,000	0	0	0	0
18	Rio Rico Highway Crossing	0	0	0	126,000	0	0	0	0
19	Rio Rico Industrial Park	25	1	16	100,000	0	0	0	0
20	Flux Canyon area	500	100	0	600,000	200,000	200,000	200,000	200,000
	Totals	3,080	616	634	$4,320,000	$1,265,000	$1,190,000	$1,190,000	$1,190,000

Magruder Data Request 3.12 of 29 June 2007 to UNSE requested the detailed completion status of ACC Order No. 62011 and others that implemented Citizens reliability improvement projects. This DR has not been answered by the filing date for this testimony.

However, a review of the UNSE response to STF DR 3.118 (and STF DR 2.1) shows the following are potential correlations of these projects to work accomplished, data for most projects was not located in STF DR 2.1:

Project 5 (Downtown Northwest), a "distribution syst Repl Nog" project expenses was $6,262,41 and completed on 2 May 2006 and "Line Repl < $10,000 replacement of old service pole with new service pole @ 544 N. Potrero Ave" expense was $5,847.90, completed on 14 Nov. 2004, with a budget of $320,000 in 1999 and $120,000 annually for 2000 through 2003. Total expenses of $12,110.31 for two jobs in 2004 and 2006 are minor to have made any impact on Project 5. They appear unassociated a pole replacement plan.

Project 9 (Valle Verde), "distribution Syst Repl Nog" project expenses was $1,529.12 and $465.43, completed on 12 April 2006 and 1 June 2006, with a budget of $180,000 in 1999 and $60,000 annually from 2000 to 2003. Project 9 specified 150 utility poles would be replaced. In 1999, 106 were replaced. This appears as an isolated pole replacement project.

Project 15, (Transmission line), an "115kV Line Replacement" project expenses of $117,768.43 was completed on 31 July 2003. This was a Citizens expense, not UNSE, based on a completion date before acquisition. A "2003-115kV line transmission" completed on 30 Nov 2003 for $6,223.21. The project budget was $320,000 in 1999 only. Two of 20 NOG poles were replaced in 1999 but 18 poles remained uncompleted in 1999. These expenses should be UNSE's. Project 15, with less than 18 poles to replace, in 1999, may have expended $123,991.64 of the $320,000 the 1999 budget on two projects completed in 2003, one by Citizens and another by UNSE. The money and tasks do not appear to match.

Project 16 (Highway 82), a "Line Repl ADOT-HWY 82 Project, Overhead Line Relocation" project expenses was $5.074.46, and completed on 31 July 2003, as Citizens expense, not USNE, based on completion before 11 August 2003. A "Distribution Syst Repl Nog, ADOT SR-82, Kino Springs" project expenses was $4,420.52, completed on 23 January 2005. Project 16 budget was $275,000 in 1999 and $120,000 annually from 2000 through 2003 with 250 utility OH poles to be replaced. In 1999, 148 had already been replaced. Thus, Citizens completed $5,074.46 of work in 2003 when $120,000 was scheduled. UNSE completed $4,420.52 two years after this project should have been completed.

Project 17 (Old Tucson Road), three jobs for "Distribution Syst Repl Nog" at 130, 144, and 190 Old Tucson Road were competed on 1 June 2005. One job for a "Distribution System Bettr. Nog" at 80 Old Tucson Road was completed 9 June 2006, with total Project 17 costs of $60,993.56 (25,325.60 + 26,749.55 + 7,711.93 + 1,206.48), with a budget of $25,000. Project 17 is scheduled only in 1999 and finished in 1999 with 9 of the 10 poles already replaced by then. No credit recommended for UNSE.

Project 20 (Flux Canyon area), for "distribution system Bettr. Nog, Flux Canyon Road, Patagonia" project costs were $11,415.03 and $933.15, completed on 20 Feb 2005 and 1 June 2005, with a budget at $200,000 per year from 2000 through 2003.

It appears that "poles, fixtures and towers" capital expenses[58] for both the Mohave (approximately four times larger than Santa Cruz) and the Santa Cruz Divisions as follows:

Year	Planned in Santa Cruz County	Total Actual in Both Counties
1999	$4,320,000	$11,336,691
2000	$1,265,000	$211,055
2001	$1,190,000	$3,113,175
2002	$1,190,000	$2,515,741
2003	$1,190,000	$1,216,447

[58] Direct Testimony of Ronald E. White on Behalf of UNS Electric, Inc., of 15 December 2006, Exhibit REW-2, Depreciation Rate Review of 24 November 2006, Schedule B, Account 364.00, Poles, Fixtures, and Towers, at 31. The Budget (Table 5) exceeded the actual expenditures 2 of 5 years for only 20% of the company.

SUMMARY for Pole Replacements.

1. The data do NOT support completing ANY Pole Replacement Projects 1 through 20.
2. UNSE records claim Citizens expenses before the acquisition.

Q. Were all the underground cables replaced as required by the ACC-approved plan?

A. The Commission approved an underground cable replacement plan from 1999 through 2003. Citizens stated the cable to be replaced had known reliability problems due to being directly buried cable (improperly installed) and the old cable was defective with high failure rates.[59]

Twelve projects are shown in Table 6 to replace 161,388 total feet (over 35 miles) of underground cable between 1999 and 2003. The budget in 1999 was $1,310,104 and annually $1,275,104 for 2001, 2002, and 2003 for a total cost of $6,406,520 to replace defective cables and to improve customer reliability.

The underground cable replacement plan required that Rio Rico and Tubac have the highest priority. A 1999 "progress to date" showed only 25,741 actual feet of cable replaced in 1999 of the scheduled 32,753 feet. Some of the first cable replacements, in the "Ft. to date" column, significantly over-ran the planed number of feet when compared to actual number of feet replaced.

Table 6 – Underground Cable Replacement Plan. *The 1999 estimates and "to date" actual installations do not meet the planned number of replacements.*

Proj. ID	Underground Cable Replacement Project	Total Feet	1999 Est. Ft.	Ft. to date	1999 ($)	2000 ($)	2001 ($)	2002 ($)	2003 ($)
1	Mariposa Manor	7,677	1,535	0	61,416	61,416	61,416	61,416	61,416
2	Monte Carlo	12,040	2,408	2,454	96,320	96,320	96,320	96,320	96,320
3	Rio Rico Urban 3	28,160	5,632	14,157	225,280	225,280	225,280	225,280	225,280
4	Preston Trailer Park	3,633	727	0	29,064	29,064	29,064	29,064	20,064
5	Tubac Country Club	6,900	1,380	0	55,200	55,200	55,200	55,200	55,200
6	Tubac Valley County Club	4,300	860	7,290	34,400	34,400	34,400	34,400	34,400
7	Palo Parado	15,530	2,706	0	108,240	108,240	108,240	108,240	108,240
8	Empty Saddle Estates	8,180	1,636	0	65,440	65,440	65,440	65,440	65,440
9	Mt. Hopkins	52,800	11,435	0	457,000	422,400	422,400	422,400	422,400
10	Meadow Hills	15,840	3,168	0	126,720	126,720	126, 720	126, 720	126, 720
11	Canyon Del Oro/Vista Del Cielo	4,500	900	1,840	36,000	36,000	36,000	36,000	36,000
12	Rio Rico Resort	1,828	366	0	14,624	14,624	14,624	14,624	14,624
	Totals	161,388	32,753	25,741	$1,310, 104	$1,275, 104	$1,275, 104	$1,275, 104	$1,275, 104

However, a review of the UNSE response to STF DR 3.118 (and STF DR 2.1) shows the following are potential correlations of these projects to work accomplished, data for most projects was not located in STF DR 2.1:

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[59] Citizens Supplemental Plan, PDF pages 26, 42, 43, 45, 52 and 53.

Project 2 (Monte Carlo) "replace URD primary wire @ 455 Baffert Dr.," cost $10,180.84, completed 13 June 2004. Project 2 annual 5-year budget is $96,320 per year to replace 12,040 feet. This job appears a single dwelling. It may have been in the project plan.

Project 5 or 6, (Tubac County Club/Tubac Valley County Club), Over Head to Underground expense of $236,873.96, completed 16 October 2005. Projects 5 and 6 budget was $317,320 (145,320+172,000). Since 1999, the Golf Resort has significantly expanded with over 200 new homes and nine holes on the golf course. This was under construction in 2005; one 13.2kV feeder cable was placed underground in the new golf course area. This is not the same as the 1999 Citizens' Projects 5 or 6, since hundreds of older homes have had underground cable for over two decades and appear as the intended recipients of the replaced underground cable.

Project 7 (Palo Parado), "Remove and replace 1000 ft single phase URD primary wire@west boundary of Palo Pardo Sub" job cost was $16,924.15 and "Line Repl>$10,000 (Nog) Replace 1000 feet of URD single primary conductor, conduit and TXF @ Palo Prado Subdivision" job cost was $4,156.57, both completed on 31 July 2003. Project 7 is for a total of 15,530 feet of underground replacement cable with an annual budget of $108,240. Due to completion date by Citizens, no credit of $21,080.72 should be claimed as UNSE expenses.

Project 9 (Mt. Hopkins), a "Kantor Substation Mt. Hopkins underground replacement project" job cost $155,440.94, completed on 31 July 2003. Project 9 budget, from Table 3, is over $2.18 million. This was a Citizens expense, not UNSE, based on the completion date.

SUMMARY for Cable Replacements.

1. The data do NOT support completing ANY Cable Replacement Projects 1 through 12.
2. UNSE records claim Citizens expense as they were before the acquisition.

Recommendation. From the above ground pole and underground cable replacements, the following expenses were Citizens since they were completed prior to UNSE acquisition on 11 August 2003. These are NOT UNSE expenses and should be deleted from the rate basis for UNSE:

a. Utility Pole Replacements

Project 15	$117,768.43		
Project 16	$ 5,074.46		
		Subtotal	$122,842.89

b. Underground Cable Replacements

Project 7	$ 4,156.57		
Project 9	$155,440.94		
		Subtotal	$159,597.51

c. For both of these pole and cable replacement projects, UNSE rate base should be decreased by **$282,440.41**. These projects were completed by Citizens prior to acquisition.

d. Based on the above jobs, NO Projects from either Plan appear completed.

e. In my opinion, the ratepayers were "short-changed" by both Citizens and UNSE on essential projects to improve reliability in the Santa Cruz service area.

As UNSE has refused to respond to data requests associated with these two projects, I feel it necessary, that until UNSE can produce records that show that

(1) At least 3,060 above ground poles were replaced as planned since 1999 <u>and</u>

(2) At least $9,155,000 was spent on the pole replacement plan since 1999, <u>and</u>

(3) At least 161,388 feet of defective underground cable has been replaced <u>and</u>

(4) At least $6,406,520 was spend on replacing defective underground cables, then I **recommend** the following actions for failure to comply with ACC Orders:

- **DELETE $9,155,000 from UNSE Rate base** for failure to replace defective OH poles <u>and</u>
- **DELETE $6,406,520 from UNSE Rate base** for failure to replace defective UG cables,

Q. What are the Power Demands for Santa Cruz service area?

A. The following Table 7 shows the actual Peak Demand for each year since 1993 and "forecasts" from organizations that have managed the Santa Cruz service area. Each band of ten MWs is the same color, so one can see how accurate the "forecasts" to actual peak for that year. Data for the past two years, 2005 and 2006, based the testimony in these proceedings have not been consistent, as discussed in the "notes" record the data sources of the data. Two forecasts are in these proceedings, one for a 3% annual growth rate and another for a 6% annual growth rate. During the 1990 to 2000 decade, census data have the annual growth was 1.7%.[60] The latest Arizona Department of Economic Security (ADES) official population predictions show a growth rate of 2.74% in 2007, 2.47% in 2010, 1.17% in 2015, and 1.06% in 2020 and continually decreasing through 2055 at 0.71%.[61] Since 90% of the county lives in this service area, it appears the 5% forecast maybe to high and the 3% growth forecast is still higher than expected, if electrical growth equals to population growth. The referenced Magruder Testimony explains and accounts for limiting load factors, such as the 100-year Assured Water Supply (AWS) requirements for the Santa Cruz Active Management Area require continual water resource sustainment. The County Comprehensive Management Plan shows that maximum population limit is estimated at 71,000,[62] with ADES showing 46,545 in 2007.

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[60] Magruder Testimony in ACC Docket No. E-01032A-00-0401, pages 181 to 184 for additional Santa Cruz service area growth details.

[61] "Santa Cruz County Population Projections 2005-2055, ADES, Research Administration, Population Statistics Unit, approved by ADES Director on 31 March 2006, found on County and ADES websites.

[62] *2004 Santa Cruz County Comprehensive Plan*, revised 2005, page 65.

Table 7. Actual and Forecast Annual Peak Demand for the Santa Cruz Area. The actual observed values, in the second column, show the actual annual peak demand in MW, with forecasts that are "higher" than forecast in red and "lower" than forecast in **blue**. Each 10 MWhr is shaded in a different background color. Newer forecasts are to the left and older to the left. Above the line between 2006 and 2007 indicates "history" which future demand predictions are below.

REAL WORLD Data		FORECAST PEAK DEMAND for the Santa Cruz Service Area												
Year	ACTUAL Peak Demand	UNSE Rate Case (3% gr)	UNSE Rate Case (5% gr)	UNS Electric and SEC	Very Slow Scenario	TEP/ UNS Electric	UNS Electric	TEP Hot Forecast	TEP High Forecast	TEP Normal-ized	RAC 2 Hot	RAC 2 Normal	Citizens C/B Analysis	Citizens Briefing
		Mar 2007	Mar 2007	Dec 2006	Oct 2005	July 2005	June 2004	Feb/Apr 2004	Feb/Apr 2004	Feb 2004	2000	2000	1999	1998?
1993	40.0													
1994	43.7													
1995	41.6													
1996	41.9													
1997	42.5													
1998	45.3													
1999	50.36												46.7	50.5
2000	52.60											50.2A	48.0	52.6
2001	50.54										60.0	55.0	49.9	55.7
2002	57.99										62.0	58.0	51.6	56.9
2003	57.64							59.1		57.5	65.0	60.0	52.4	58.2
2004	60.768						61.4	61.4	64.4	59.7	67.0	62.0	54.5	59.5
2005*	69.408 or 69.6			69.5			63.6	63.2	63.6	66.8	61.9	69.0	64.0	60.7
2006*	71.7 or 73.152			71.1	72.7		65.3	64.9	65.8	69.0	64.0	72.0	66.0	
2007				74.0	74.1	63.6	66.7	66.5	67.9	71.3	66.1	74.0	68.0	
2008		76.1	76.1	76.5	76.5	65.3	68.1	68.0	70.1	73.5	68.2	76.0	70.5	
2009		78.4	79.9	79.1	77.0	66.7	69.4	69.5	72.2	75.8	70.3	78.0	73.0	
2010		80.7	83.9	81.7	78.5	68.1	70.8	71.0	74.5	78.2	72.5	80.0	74.0	
2011		83.2	88.1	84.3	79.9	69.4	72.2	72.5	76.8	80.6	74.7			
2012		85.7	92.5	86.9	81.5	70.8	73.6	74.0	79.2	83.1	77.0			
2013		88.2	97.1	90		72.2	74.9	75.4	81.6	85.7	79.4			
2014		90.9	102.0	92		73.6	76.1	76.7	84.1	88.3	81.8			
2015		93.6	107.1	95		74.9	77.3	78.8	86.7	91.0	84.3			
2016		96.4	112.4	98		76.1	78.5	79.3						
2017		99.3	118.1	101		77.3	79.7	80.6						
2018		102.3	124.0	103		78.5	80.9	81.9						
2019				105		79.7	82.0	83.3						
2020				107		80.9	83.3	84.6						

Historical Peak Demand Data

Historical Forecast Peak Demand Data

Table 7. Actual and Forecast Annual Peak Demand for the Santa Cruz Area. The actual observed values, in the second column, show the actual annual peak demand in MW, with forecasts that are "higher" than forecast in red and "lower" than forecast in **blue**. Each 10 MWhr is shaded in a different background color. Newer forecasts are to the left and older to the left. Above the line between 2006 and 2007 indicates "history" which future demand predictions are below.

REAL WORLD Data		FORECAST PEAK DEMAND for the Santa Cruz Service Area												
Year	ACTUAL Peak Demand	UNSE Rate Case (3% gr)	UNSE Rate Case (5% gr)	UNS Electric and SEC	Very Slow Scenario	TEP/ UNS Electric	UNS Electric	TEP Hot Forecast	TEP High Forecast	TEP Normal-ized	RAC 2 Hot	RAC 2 Normal	Citizens C/B Analysis	Citizens Briefing
		Mar 2007	Mar 2007	Dec 2006	Oct 2005	July 2005	June 2004	Feb/Apr 2004	Feb/Apr 2004	Feb 2004	2000	2000	1999	1998?
2021				109		82.0		86.3						
2022						83.3		88.0						
2023								89.8						
2024								91.6						
2025								93.4						
2026								95.3						
2027								97.2						
2028								99.1						
2029								101.1						
2030								103.1						
2031								105.2						
2032								107.3						
2033								109.4						
2034								111.6						
2035								113.9						
2036								116.1						
2037								118.5						
2038								120.8						
2039								123.2						
2040								125.7						

Historical Peak Demand Data

Forecast Peak Demand Data

<u>Forecast Data Sources and notes (reading from left to right columns)</u>

***Actual Peak Demand (1993 to 2006)** – In the UNSE Rate Case, ACC Docket E-04204A-06-0783, the peak loads for 2006 and 2005 were given as 71.7 MW and 69.6MW, in UNSE response to ACC Staff data request STF 1.1. In USNE response to MM DR 1.15 the peak load for 2006 was provided by UNSE to be 73.152 MW was provided as the 2006 peak load. In this UNSE response to MM DR 1.15, the peak load demands for 2003 through 2006 were provided which included a 2003 peak at 54.144 MW that occurred after 11 Aug 2003, under UNSE, while the actual 2003 peak occurred under Citizens at 57.64 MW earlier that summer. Additional peak data were in TEP's response to MM Data Request 221.c in ACC Docket E-01032A-99-0401.

UNSE Rate Case (3% gr, 5% gr((Mar 2007) – In UNSE's response to MM Data Request 1.15 (Excel spread sheet) in ACC Docket E-04204A-06-0783 for years 2008 through 2018 using a 3% and 5% growth rates.

UNS Electric and SEC (Dec. 2006) – For 2005 to 2012, from Testimony of Ed Beck in UNS Electric Rate case ACC Docket E-04204A-06-0783 and from 2013 to 2021 from the UniSource SEC Form 25 submitted in Dec 2006 and Exhibit MJD-1 to Michael DeConcini in the above UNS Electric Rate case. The SEC filing also included the earlier years, rounded off to an even MWhr as Weather Normalized Peak Demand Forecast.

UNSE "Very Slow" Scenario (Oct 2005) – From UNSE Annual Peak Load Forecast, emails in March 2006, from MM Data Request 1.9.g in ACC Docket E-04204A-06-0783.

TEP/UNS (July 2005) – From Beck Testimony of 8 July 2005, Exhibit 3 (Annual Peak Load Forecast for Santa Cruz County)

UNS Electric (June 2004) – From UES "Long-term Transmission Plans for Santa Cruz County UNS Electric System," June 2004. For years 2021 and later, the forecast is extrapolated based on a 2% growth factor.

TEP Hot, High, and Normalized Forecast (Feb/April 2004) – From Exhibit 4 (February 2004) where TEP forecast is for the average year (also in the RMR report for 2005, 2008, 2012) and the "high" for years that are hotter than normal.[63] This also has been published as "Nogales Retail Peak Forecast – April 2004:" with the years 2004 to 2020 designated as the "UniSource Forecast (MW)" and the years 2021 to 2040 as "Extrapolated Forecast (2% growth factor (MW)

UniSource Energy Services – Loads & Resources Peak (weather normalized) Demand Forecast (used by UniSource for the competition for a new Purchase Power Agreement for Santa Cruz County (February 2004)

RAC2 Hot, Normal (2000), Testimony of Rasel Craven, Citizens Director of Engineer, May 1, 2001, Docket No. L-00000C/F-01-0111, Line Siting Case No. 111, as Exhibit RAC-2, which indicated on June 30, 2000, a record of 50.2 MW was reached (marked by A) above. Values for 2001 to 2003 are from testimony, from 2004 to 2010 from Exhibit 4 (February 2004) as footnoted above. The "normal" and "hot" were for years which were average or higher than average. The R.W. BECK & Co. determined the RAC-2 forecasts in early 2000.

Citizens' Cost-Benefit Analyses (1999) of Transmission-Line Alternatives, ACC Docket E-01032A-98-0611 in Exhibit F of July 13, 1999 at Nogales Tap for "normal weather."

Citizens Briefing (1988) given to the Joint Santa Cruz County/City of Nogales Energy Commission in February 2001; however, content appeared to be dated about 1988.

[63] See Exhibit 4 from the TEP and UES "Response to Commission Questions and Updated Response Plan for Santa Cruz County" of 9 February 2004, in ACC Docket No. E-01032A-99-0401.

During the 1990 to 2000 decade, census data have the annual growth was 1.7%.[64] The latest Arizona Department of Economic Security (ADES) official population predictions show a growth rate of 2.74% in 2007, 2.47% in 2010, 1.17% in 2015, and 1.06% in 2020 and continually decreasing through 2055 at 0.71%.[65] Since 90% of the county lives in this service area, it appears the 5% forecast maybe to high and the 3% growth forecast is still higher than expected, if electrical growth equals to population growth. The referenced Magruder Testimony explains and accounts for limiting load factors, including the 100-year Assured Water Supply (AWS) requirements for the Santa Cruz Active Management Area require continual water resource sustainment. The County Comprehensive Management Plan shows that maximum population limit is estimated at 71,000,[66] with ADES showing 46,545 in 2007.

Based on this data and an analysis local situational factors it was determined that "between 2040 and 2050, the maximum peak electrical load is estimated to be between 115.8 MW and 137.3 MW" for this service area.[67]

Q. What are the local generation capabilities to meet these loads?

A. There are many conflicts within the UNSE Testimony as to the local generation capabilities at the Valencia Substation in Nogales, Arizona, the only generation capability in this service area.[68] There are three combustion generators at the Valencia substation. Each is rated for site peak "nameplate rating" of 17.65 MW with a maximum site peak rating of 19.15 MW. I will use a nominal 16 MW is used throughout this Testimony.[69] Further, during the last rate case test year in 1998, power generated by each turbine was tested greater than 16 MW.

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64 Magruder Testimony in ACC Docket No. E-01032A-99-0401, pages 181 to 184 for additional Santa Cruz service area growth details.

65 "Santa Cruz County Population Projections 2005-2055, ADES, Research Administration, Population Statistics Unit, approved by ADES Director on 31 March 2006, found on County and ADES websites.

66 *2004 Santa Cruz County Comprehensive Plan*, revised 2005, page 65.

67 Magruder Testimony in ACC Docket No. E-01032A-99-0401, pages 181 to 185. Using a possible long-term improvement in efficiency (Demand-Side Management), distributed generation resources based on the ACC's Renewable Energy Standard and Tariff (REST), and other EC and EE results, a reasonable upper limits of the peak electricity demand for the UNSE service area" could be between "99 and 109 MW." at 184.

68 Direct Testimony by Edmond A. Beck on Behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Beck Direct Testimony", at 6, three turbines have a "combined output of approximately 47 [48] MW" at 6; "an emergency UNS Electric 46 kV line that ties TEP's system and can provide approximately 10 [22] MW of electricity" at 9; "the combination of the four generators in Nogales and the 46 kV line may not be sufficient to restore the customer's entire load" at 9. See DeConcini Direct Testimony, "UNS Electric also owns 65 MW of generation capacity within Santa Cruz County load area that is used for reliability must run circumstances" at 1; "approximately 65 MW of generation ... generation consists of three 15 MW simple cycle combustion turbines and a new 20 MW simple cycle combustion turbine" at 3; Schedule D, FERC Form 1, 2005/2Q, "Total Installed Cap (Max Gen Name Plate Ratings-MW) 54.00" and "Net Peak Demand on Plant – MW (60 minutes) 59" at page 402.

69 This information was in TEP's response in ACC Docket No. E-01032A-99-0401 to Magruder data request MM-329.a, "Design Data," for turbine no. 214354. Since all are the same model, and for consistency with other information, the nominal value of 18 MW per turbine have been used in this Testimony.

A new General Electric LM-2500 turbine was operational on 31 May 2006. It has a nominal 20 MW capability; even through its normal rating is 22.1 MW.[70]

The nameplate total normal peak for three turbines is 52.95 MW (3 x 17.65) while the maximum peak is 57.45 MW (3 x 19.15 MW). Thus, a nominal value for these three turbines of 48 MW (16 x 3) is rather conservative. Experience has shown that turbines operating at a maximum power at 108% (19.15/17.65) in this case, are a common practice.[71]

Summary of local generation capabilities are as follows:

Nominal Load	**68.0 MW** (48+20)[72]
Nameplate Load:	**75.12 MW** (52.95+22.1)
Maximum Peak Load:	**84.99 MW** [57.45+(1.1x22.1)]

These turbines are excellent "peaker" turbines, for a short duration peak load that might occur during the summer. One turbine will be necessary to meet such a peak load. As indicated in Mr. Beck's Direct Testimony, the Western Area Power Administration (WAPA) line between the APS Saguaro Power Station, has constrained Full Transmission point-to-point service to 65.8 MW from 1 January 2007 through 28 February 2008.[73] The WAPA transmission charge is $0.0078/kW-month.[74]

Q. If you are limited by WAPA to only 65.8 MW, what alternatives exist to meet peak loads?

A. There are several alternatives.

One is work with WAPA to obtain higher capacity. As presented by TEP's Mr. Ed Beck at the ACC 2007 Summer Preparedness, UNSE is working with WAPA for a solution. In Mohave service area, by changing from point-to-point service to network service, the

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70 General Electric "LM2500 Aeroderivative Gas Turbines, which also states "Full Power in ten minutes" which improves reaction time during an outage or if needed to meet a peak load greater than is being received on the 115 kV transmission line is found at the below web site http://gepower.com/prod_serv/products/aero_turbines/lm2500... (reviewed 11 June 2007)
My experience is that LM2500's, from a cold start, are fully operational in much less than ten minutes. One can actually "turn the key" on the bridge of a warship and be underway five or so minutes. It takes that long to bring in the lines if alongside a pier and up to 30 knots in less than ten minutes at 107% of rated power. The US Navy has been using LM2500s since the early 1970s.

71 The US Navy uses the General Electric LM2500 turbines on all cruisers, destroyers and frigates, where operations as high as 110% of rated power are frequently for short periods of time, if extra power is needed. These turbines are in many electric power plants. Jet aircraft turbines frequently "go buster" when exceeding normal power. This Testimony has not used this capability that inherently exists with these turbines.

72 The UNSE response to ACC Staff data request STF 1.1 is incorrect, each older turbine is rated at 16 MW and not 14 MW or greater and the LM2500 is not a 19 MW turbine. The numbers above are correct. This kind of error, using 61 MW vice 68 MW is important as the local load also is increasing a few MW per year, every MW is important, and such "round-offs" are despicable. In addition, UNSE response to Magruder data request MM DR 1.9a stated "UNS Electric's only generation facility is the 70 MW (nameplate) four-unit Valencia..."

73 DOE WAPA, Desert Southwest Regional Office Contract No. 87-BCA-10140, Amendment 3, Exhibit A, Revision 19, page 3.

74 *Ibid.*, Exhibit B.PPK, page 1, para 3.

resultant additional capacity made the constraint problem go away.[75] Mr. Beck is negotiating with WAPA now to make this same change for the Santa Cruz service area. Also, changing from point-to-point service has a lower transmission charge, which will be an important benefit, as this charge is directly passed through to the ratepayers,

A second is to use one of the "peaker" turbines in Nogales to generate the additional power above 65.8 MW required by the local load. Mr. Beck's Direct Testimony provided the percent of time and MW demand for these peaker needs. Table 8 below expands this alternative.

Table 8. Peaker Turbine Operations in Nogales. *Using UNSE Additional Generation and MWhs per Year, a Very Conservative Cost can be estimated. Actual cost should be less than One-Third that shown.*

Year	Load Exceeds 65 MW[76]	Hours per year	Additional Generation Required[77]	MWh per Year (note 1)	Annual Cost @ $150/MWh (note 2)
2006	1.7%	148.9	4.7 MW	700	$104,975
2007	2.2%	192.7	7.0 MW	1,349	$202,335
2008	2.9%	254.0	9.5 MW	2,413	$361,950
2009	3.4%	297.8	12.1 MW	3,603	$540,507
2010	4.1%	359.2	14.7 MW	5,280	$792,036
2011	5.5%	481.8	17.3 MW	8,335	$1,250,271
2012	6.3%	551.9	19.9 MW	19,983	$1,647,422
	7-year Totals	2286.3	2286.3 MW	41,663	$4,899,490

Note 1. This assumed that the Additional Generation was required for all the hours per year, which is not reasonable; however, the result will be higher than reality.
Note 2. On the average, a LM2500 turbine generates electricity for less than $150/MWh. In 2000, actual results for the older combustion turbines was about $158/MWh.

Table 8 is too conservative, as the Additional Generation is the "peak" generation necessary when only 65.8 MW is all that is available on the WAPA lines. Still conservative, the total MWh is the area under a daily "load – time" curve. In general, this is about two-thirds the peak, thus the annual costs are reduced by at least 1/3rd so for 7 years, then $1,633,163 (4,899,490/3) is the cost for peaker operation.[78] The TEP proposed single-circuit 138-kV second transmission line cost is over $100 million, thus peaker costs are important but such cost are not the critical project driver. The real mission driver is a second transmission line for redundancy, to provide a backup line, necessary to improve transmission reliability (discussed later). This example shows that additional power is needed to the Santa Cruz service area, preferably from external lower-priced generated power.

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[75] Beck Direct Testimony at 16.
[76] *Ibid.*, at 10.
[77] *Ibid.*, at 11.
[78] *Ibid.*, at 10, where Mr. Beck said "The load forecasts show that Santa Cruz County has a very short duration peak."

Q. How much power can the existing 115 kV transmission line carry?

A. We need to first determine the physical characteristics of this line. Table 9, shows these characteristics for each segment. Based on Table 7 above, this line has adequate capacity through at least the year 2040. There are two possible bottlenecks; one would be when over backup WAPA line rated at 120 MW between Del Bac substation and the Nogales Tap. The other is the last 4.8 mile segment north of the Valencia substation in Nogales. Based on the four substations in this service area, less than 50% of the total loads will be required for Valencia, thus this 68 MW segment is adequate until the total demand exceeds 136 MW or higher.

Table 9. ***Existing 115 kV Transmission Lines Capacity Ratings in the Santa Cruz Grid.*** "Thermal" ratings determine the maximum physical capacity or load carrying capabilities for transmission lines.[79]

Line Status	Line Section (Location)	Length in miles	Conduct or Type	Structure Type	Thermal Ampacity Rating (amperes)	Thermal Rating at 115 kV (MVA)
WAPA-owned Lines (before Citizens 115 kV)	Del Bac (WAPA) to Nogales Tap (Tucson)	---	---	---	603*	**120 MW**
	Adams (WAPA) to Nogales Tap (Tucson)	---	---	---	803**	**160 MW**
Existing 115 kV transmission line	Nogales Tap (Tucson) to Amado (Kantor substation)	27.7	559.5 AAAC	Steel Monopole	663**	**132 MW**
	Amado (Kantor) to North Rio Rico (Canez substation)	13.5	559.5 AAAC	H-Frame	663**	**132 MW**
	North Rio Rico (Canez) to South Rio Rico (Sonoita substation)	3.3	559.5 AAAC	H-Frame	663**	**132 MW**
	South Rio Rico (Sonoita) to the Conductor Change	3.6	559.5 AAAC	H-Frame	663**	**132 MW**
	1Conductor Change to Nogales (Valencia substation)	4.8	4/0 ACSR	H-Frame	340***	**68 MW**
Proposed 115 kV line from Gateway	115 kV Gateway Substation to Nogales (Valencia substation)	3.5	559.5 AAAC	Steel Monopole	663**	**132 MW**

* Thermal ampacity ratings for Del Bac and Adams substations to Nogales Tap at the Nogales Switchyard in Tucson were obtained from the WSCC database.
** The thermal ampacity rating for the 559.5 AAAC conductor reference is the *Southwire Handbook*, (*Citizens Santa Cruz 2002 Plan of Action).*
*** The thermal ampacity rating for the 4/0 ACSR conductor is from the Westinghouse Transmission and Distribution Reference Book.

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79 *Citizens Communications Company Arizona Electric Division – Santa Cruz District Transmission System Action Plan*, June 2002, filed at ACC Docket Control July 1, 2002, hereafter "Plan of Action." This plan was developed by Power Engineers, Inc., a respected power analysis company for Citizens. Power Engineers and Dames & Moore prepared the "Santa Cruz Electric Division Transmission Alternatives and Plan of Action" in April 1999 (with two supplemental filings in the TEP/UNS Updated Outage Response Plan, February 9, 2004) the "plan of action" in the title of ACC Docket No. E-01032A-00-0401. The Citizens' environmentalist used the *Plan of Action* in 1999 for Line Siting Case 111 for the Citizens' 115 kV transmission line part of the TEP proposed 345 kV transmission line hearings. Thus, outside technical and environmental assistance consultant's experiences were consistent to augment Citizens staff from 1999 through 2002. pages 8 and 9. This Study uses MVA (apparent power) and MW (active power) interchangeably when discussing this table, thus the right column shows MW for each line segment.

Other factors, such as the present WAPA 65.8 MW constraint for power sources to the UNSE transmission system, substation upgrades involving higher-power rated reactive capacitors, voltage regulators, and other equipment. Power Engineering ran a series of power loading cases using the existing 115 kV line, and was able to have a safe load carry capability up to 95 MW while meeting NERC/WECC reliability criteria.[80]

Q. If the existing 115 kV transmission line is adequate, why is a second transmission line needed?

A. The short answer is simple, REDUNDANCY. When a second, independent line (or for the matter anything) can provide a parallel path, then a failure of a component does not have to result in an outage because a second, redundant line is present. Using Reliability Engineering, I showed how this works based on over ten years of data, from 1994 through 2004 in the Santa Cruz service area, using actual failure and outage data.[81]

The basis results of this analysis are summarized as follows:

a. Total Outage per Customer per year. The total number of minutes of outage per customer per year, over this 10-year time frame, was 201.4 minutes of outage.

b. Total Storm Outages per Customer per year. Nearly 106 minutes of outage per customer were during storms that occur significantly less than 5% of the time.

c. Total Other Outages per Customer per year. All Other outages were 88 minutes per customer.[82]

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[80] *Ibid.,* Due to the distance from the generation sources for the Santa Cruz load, line voltage changes when demand suddenly changes, usually dropping. The WECC planning level criteria has established that a ± 5% voltage must be maintained with respect to the specified voltage, thus the 115 kV can vary from 109.25 to 120.75 kV and still be considered to be within normal limits. These cases, looked at this voltage, and when outside of these limits, shown in red, are such cases (see this summarized in Docket No. E-01032A-00-0401, Magruder Testimony of 8 July 2005, pages 38 and 39). The primary way to reduce these voltage drops is to install capacitors that can "hold" the voltage until the supply source adjusts for this change. The amount of these capacitors is expressed in millions of volt-ampere-reactance (MVAR). These "cases" were to assess various MVAR options so the utility would purchase and install what is necessary to be compliant with WECC planning criteria. It is noted that under none of these cases was the 115 kV transmission line stressed, only at 70% of its normal thermal capacity was observed at a 95 MW Santa Cruz load. A second, recurrent problem observed was that the Valencia 115:13.2 kV transformers were overloaded. This is because they need more circuits or higher capacity transformers. The primary requirement for the 13.2 kV capabilities for the Gateway substation are to off-load the Valencia transformers which will then increase the capacity for the 115 kV transmission line. The Gateway substation, with additional 115:13.2 kV transformers and circuits are an essential capability which is necessary to off-load Valencia.

[81] ACC Docket No. E-01032A-99-0401, Magruder Testimony of 8 July 2005, Appendix B, "Electric Reliability Data in the Santa Cruz Service Area, 1994-2004," pages 109 to 116, and Appendix C, "Reliability Engineering Analysis, pages 117 to 130.

[82] The sum of Storm plus Other is 204 minutes, while the Total is 201. This table were taken directly from the Citizens monthly reports to the ACC; however, this difference of less than 1.5% is perceived to be cumulative round-off error. The individual column sums will be used and the "total" only when discussing in the "aggregate" for the whole system. Magruder Testimony, Table C-3, page 111 for analysis.

d. Total Supplier Outages per Customer per year. "Supplier" outages were all before a switch was installed in 2000 at the Nogales Tap. No outages have occurred since. The 17.8 minutes attributed to Supplier outages should be almost zero in the future.

e. Total Transmission Outages per Customer per year. The total "transmission" outages were 62.8 minutes, of which nearly 42 minutes were during storms, or 66.6%.

f. Total Distribution Outages per Customer per year. Total "distribution" outages were 107.1 minutes, considered excessive. Nearly 63 minutes or 59.6% were during storms.

The analysis used Citizens data provided monthly to the ACC and before implementation of the IEEE Standard 1366, which has been used since 2004 by UNSE in this service area. During this decade, there were 4 supplier outages, 20 transmission outages, 4,297 distribution outages and 41 scheduled (by Citizens) outages.

Using Reliability Engineering methodologies, table 10 was derived, which looked at each subsystem (supply or generation, transmission, distribution)'s outages and those scheduled, to determine the percent of the time that subsystem was operational and available. When one multiplies the number of hours in a year times (1.0 minus Availability %), then you can determine the percent a subsystem in not operational or available.

Table 10. ***Santa Cruz System and Subsystem Availability by Outage Type.***[83]

Kind of Outage	Availability (storm)	Availability (other)	Total Availability
Supply	99.99973181%	99.99688451%	99.99653412%
Transmission	99.99204024%	99.99469123%	99.98673424%
Distribution	99.98672316%	99.99194378%	99.98333611%
Scheduled	Not Applicable	99.99983762%	99.99983762%
		Total Availability	99.96644492%

When one considers "redundancy" but installing a second, independent and identical component, then we can determine the impact on operations, and for Transmission, this is very logical and is easy to understand. The following is from the Magruder Testimony.

"**D.3 Impact of the Second Transmission Line between the Nogales Tap and Nogales**. When a second, redundant transmission line is installed, the overall transmission reliability will be significantly improved. Using mathematic rules for the addition for probabilities, were the "sum of the individual probabilities minus their product" yields the combined probabilities for two independent events we determine the Availability or probability of success (not having a failure) for Transmission-Total, from Table D-2 [now Table 10], is 99.986734241%.

"Assume the Availability of a second transmission line is both independent and equivalent to that from existing 115 kV line between 1994 and 2003, or 99.986734241%. We can determine the resulting probability of success (Availability) for having one of these two transmission lines always

83 This is Table D-3, Santa Cruz System Availability (A) by Outage Type in ACC Docket No. E-01032A-99-0401, page 118.

available by adding this number and then subtracting their product, given by (all "A" values given as decimals) then,

A (transmission-1 of 2 lines) = A (Transmission-Total) + A (Transmission -Total) – [A x A]
A (transmission-1 of 2 lines) = (0.99986734241+ 0.99986734241) – (0.99986734241x 0.99986734241)
A (transmission-1 of 2 lines) = 1.999973456482 – 0.999973468658
A (transmission-1 of 2 lines) = 0.99999998782 or 99.999998782%

"Thus, 99.999998782% of the time, one of these two switches [or lines] will always be available, or conversely, 1.0 – this number is the amount of time neither of these two switches [or lines] will be available, or 0.000001218% of the time. Using 33,557,600 seconds per 365.25 days per year (x 24x60x60), we see that 0.409 seconds per year, both transmission lines (the existing and the second, redundant, independent) will NOT be available. Since there was a total MTBF[84] for transmission line outages of 4,381 hours (from Table D-1), then an outage due to one of these two transmission lines NOT being available, based on these assumptions is shown below.

"One transmission outage every 4,381 hours (MTBF), but there are only 0.409 seconds per year that neither of these two transmission lines are available, so for one of these failures to occur during this interval, we see the

"Computed MTBF with a redundant transmission line =
MTBF (two lines fail) = (4,381 hours/failure 60 min x 60 sec) / (0.409 sec/year)
MTBF (two lines fail) = 38,561,369 years per failure
Thus, once every 38 million years, a failure will occur by both of these transmission lines at the same time. Note, *this calculation assumed the following:*

a. That the second transmission line was redundant and independent of the first line.
b. That the second transmission line had the same outages (MTBF) as the existing 115 kV line had during the 1994 to 2003 time frame.

"It is important to note that the MTBF for both the existing and the second transmission line failure is NOT dependent upon voltage, size or location, just that a second, redundant, and independent transmission line is installed. Further, these data are conservative as some of the prior root causes of failure have been mitigated, thus the existing 115 kV transmission line would, today, have a higher MTBF and lower MTTR than it had during the 1994 to 2003 period."[85]

Q. What else has improved the reliability in Santa Crux Service Area?

A. The Citizens Plan included and accomplished the following prior to the sale to UNS Electric:

a. Generator synchronization equipment to automatically close and re-establish the WAPA tie.
b. At the Nogales Tap, the system synchronization equipment was installed.
c. A new three-ring bus breaker was installed to reduce interruptions.
d. At the Valencia substation, the 115 kV breakers and controls, voltage regulation equipment, protective relay and control work was completed.
e. At the Sonoita substation, voltage regulation, controls and building were completed, 115 kV sectionalization equipment was installed.
f. At the Kantor substation sectionalization equipment installed.

[84] This is Mean Time Between Failure (or outage) or MTBF = Hours Operational / number of failures.
[85] See Magruder Testimony in ACC Docket No. E-01032A-99-0401, pages 120 to 121.

g. General Electric inspected, tested and calibrated the generation protection and control systems, voltage regulator was replaced, DC power system used to black start the turbines was upgraded with redundant batteries and low voltage warning alarms, and some protective relay improvements made.

h. The SCADA system was improved with an operator station at the Valencia generation station (now moved to Tucson), and remote outage monitoring system completed (but then replaced by TEP's system).

ALL these improved reliability in this service area.

Q. What reliability issues remain in this Service Area?

A. Based on the analysis in the Magruder Testimony of July 2005, distribution outages were the most significant type of outage with higher outage rates during storms.

Table 11. ***Average Hours of Outages per Customer.*** *Storms caused most outages and Distribution subsystem outages were caused the customer's longest outage times.*[86]

Year	Major Storms			All Other Outages				
	Supplier	**Trans**	**Dist**	**Supplier**	**Trans**	**Dist**	**Sched**	**Total**
1994	0.000	0.000	0.622	0.116	0.000	0.976	0.000	1.714
1995	0.000	0.000	0.098	0.000	0.000	0.968	0.000	1.066
1996	0.235	0.000	0.684	0.000	0.035	0.067	0.000	1.336
1997	0.000	0.000	2.393	0.000	0.000	1.117	0.000	3.509
1998	0.000	2.838	2.199	2.614	4.617	0.583	0.000	12.850
1999	0.000	0.166	0.808	0.000	0.000	0.715	0.048	1.737
2000	0.000	1.404	1.259	0.000	0.000	0.572	0.004	3.238
2001	0.000	0.828	1.426	0.000	0.000	0.416	0.052	2.722
2002	0.000	0.000	0.288	0.000	0.000	1.136	0.032	1.456
2003	0.000	1.737	0.654	0.000	0.000	0.531	0.006	2.928
2004	0.000	0.000	NA	0.000	0.000	NA	NA	NA
Totals	**0.235**	**6.973**	**10.431**	**2.730**	**4.652**	**7.081**	**0.142**	**32.556**
Average per year in hours	**0.024**	**0.697**	**1.043**	**0.273**	**0.465**	**0.709**	**0.014**	**3.356**
Average per year in minutes	**1.4**	**41.8**	**62.6**	**16.4**	**28.0**	**42.5**	**0.9**	**201.4**

When UNSE purchased Citizens, the monthly reporting format to the ACC Staff changed, thus continuing to use the above "total system" reliability approach lacked the necessary distribution data. It should be noted that all the "unreliable" years are included in Table 11. The system reliability improvements become obvious when the outage trends decrease starting in 2000 when the Action Plan was showing progress. At 201.4 minutes per year, the average customer outage duration compares favorably with the Rural Utilities Service

[86] This is Table C-3, Average Hours of Outages per Customer, in Magruder Testimony in ACC Docket No. E-01032A-99-0401, page 111.

Bulletin 161-5 standard for total customer outages in rural areas not to exceed 300 minutes per year.[87]

The Commission started using several indices in IEEE Std 1366™-2003[88] in 2004 and UNSE started maintaining data required to compute these distribution reliability indices. Table 12 shows the definitions of common IEEE Std 1366 indices.

Table 12. Definitions of Key Distribution Reliability Indices. *These are used to report distribution reliability data to the ACC Staff by utilities in Arizona.*

Index	Definition
Average Service Availability Index (ASAI)	This index represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. Mathematically, this is given by the following equation: $$\textbf{ASAI} = \frac{\Sigma \text{ Customer Hours Service Availability}}{\text{Customers Hours Service Demands}}$$
Customer Average Interruption Frequency Index (CAIFI)	This index gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once regardless of the number of times interrupted for this calculation. Mathematically, this is given by the following equation: $$\textbf{CAIFI} = \frac{\Sigma \text{ Total Customers Interrupted}}{\text{Total Number of Customers Interrupted}}$$
Momentary Average Interruption Frequency Index (MAIFI)	This index indicates the average frequency of momentary interruptions. Mathematically, this is given by the following equation: $$\textbf{MAIFI} = \frac{\Sigma \text{ Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$
System Average Interruption Duration Index (SAIDI)	This index indicates the total duration for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption. Mathematically, this is given by the following equation: $$\textbf{SAIDI} = \frac{\Sigma \text{ Customers Interrupted Durations}}{\text{Total Number of Customers Served}}$$
System Average Interruption Frequency Index (SAIFI)	This index indicates how often the average customer experiences a Sustained Interruption over a predefined period of time. Mathematically, this is given by the following equation: $$\textbf{SAIFI} = \frac{\Sigma \text{ Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

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[87] Direct Testimony of Steve Taylor Electric Utility Engineer, Utilities Division, Arizona Corporation Commission of 28 June 2007, hereafter "Taylor Direct Testimony", Exhibit ST-1, "Staff's Assessment of Quality of Service, Used and Useful, Construction Work in Progress Capital Assets, Black Mountain Generation Station" of 28 June 2007, hereafter "Taylor Staff Report", at 2.

[88] *IEEE Guide for Electric Power Distribution Reliability Indices*, IEEE Std 1366™-2003, hereafter "IEEE Std 1366" of 14 May 2004.

Earlier in this testimony I used the term "Availability" which is the same as Average Service Availability Index (ASAI) shown in Table 10, for the distribution subsystem is 99.9867% during storms, 99.9919% during other times with a total Availability or ASAI of 99.9833% when the two are combined using probability addition mathematics. In Table 11, the average of 201.4 minutes of outage per customer per year is the same as System Average Interruption Duration Index (SAIDI). As shown in Table 10, SAIDI, or the bottom line, is computed for each component of the Santa Cruz system during storms and during other conditions. This is the ten year average with individual (in hours) SAIDI.

Most of the data are available to compute Customer Average Interruption Frequency Index (CAIFI); however, pre-2004 data are inadequate for Momentary Average Interruption Frequency Index (MAIFI) and System Average Interruption Frequency Index (SAIFI).

In the UNSE Response to Data Request STF 1.1 of 12 March 2007, UNS Electric distribution SAIDI was reported as 68.4 minutes in 2004, 89.3 minutes in 2005, and 153.1 minutes in 2006. Table 10 shows a ten-year average of 62.6 minutes in storms and 42.5 minutes during other times for a total SAIDI of 105.1 minutes of distribution outage per customer per year. The years of 2004 and 2005 were better while 2006 was considerably worse. Only two years (1997 and 1998)[89] were total distribution outage durations longer than 2006 and conversely eight of the ten years were better than 2006. In 2005 there was a Category C outage at the Kantor substation on 27 May 2005. A detailed analysis of this major day incident is in my testimony in ACC Docket No. E-01032A-99-0401.[90]

5.2 Improvements Initiated by UNSE in the Santa Cruz Service Area.

See Mr. Beck's Direct Testimony.

5.3 Conclusions.

Some reliability improvements have been made in the Santa Cruz service area but the failure to install a second transmission line is a disgraceful act in view of the direction from the Commission, especially from TEP's senior executives, by relying on a proposed 345 kV line that will not ever be constructed. The reasons are beyond the scope of these hearings and several alternatives have been proposed but TEP has not listened nor wanted to listen to logical, beneficial, and less costly options. TEP seems determined to want the most expensive

[89] The duration of distribution outages in 1997 was 210.6 minutes [(2.393 + 1.117) x 60] and 1998 was 166.9 minutes [(2.199+0.583)x60]

[90] Magruder Testimony of 8 July 2005, ACC Docket No. E-01032A-00-0401, D.4.2 Results During an Actual Outage in May 2005, pages 123 and 124. The root cause of this accident was the failure to remove reverse power relays for the Valencia turbines which was reported to Citizens by General Electric on 21 April 1999 (in footnote 89), which extended the outage several hours, and prevented restoration of power within the advertised 10 to 15 minute window by using the new 48 kV line and remote TEP generator controls.

options so their "rate base" is higher, thus more revenue for the Company. TEP has utterly failed to honor the Project Development Agreement in the CEC Application.

5.4 Recommendations.

There are several important recommendations to be considered.

1. Decrease the rate base by $15,561,520 for failure to comply with an ACC Order No. 62011 (see above) and ensure compliance with all actions in the ACC Staff-Citizens Settlement Agreement and
2. Complete and continue to take ALL actions required by the City of Nogales-Citizens Settlement Agreement.
3. Ensure that the UNSE rate base does not include expenses incurred prior to the acquisition, such as the $122,842.89 for utility pole replacements and $159,597.51 for underground cable replacements presented above.
4. Obtain more access on the WAPA lines, with considerably lower wheeling costs, than using TEP facilities.
5. Be consistent with objective data for load capacities when presenting operational data.
6. Compute reliability indices at the substation level, as required by NERC/WECC reliability criteria.
7. Delete considerations of a 345 kV line and get started with a second parallel transmission line for each substation, either 115/138 double-circuit or a backup 46/59 kW double-circuit.
8. AND to cease "fear mongering" by saying the "lights are going out" in Nogales in 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, and later until firm clear alternatives have been objectively considered.

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Part VI – ISSUE 4

CARES and CARES-M Tariffs

6.1 Concerns about CARES and CARES-M Programs.

These are two important programs for lower income ratepayers, Customer Assistance Residential Energy Support (C.A.R.E.S., hereafter CARES) and Medical CARES or CARES-M.

The CARES-M program restricted to those who have live-saving electrical equipment needs. Unfortunately, the Company does not know the types of such equipment its customers have, if such equipment has back-up batteries, or how long such equipment might continue operations during a power outage. Also, "The Company does not typically contact outside agencies during a power outage regarding CARES customers" was the response to a data request which requested "how does UNSE coordinate with local authorities, such as local fire and/or police departments during an electrical outage."[91]

In Santa Cruz County the local fire departments, sheriff and police have lists of known residences that have electrical life-support equipment. During emergencies, these agencies attempt to contact these residences. There are reasonable and critical safety issues involved here that need immediate action by USNE to establish and maintain coordination, procedures and policies required for the safety of its customers. For example, in response to "please provide a copy of any 'check sheets' and company policies that are located at the 'Call Center' that are used for CARES-M customers" was "please clarify what is meant by 'check sheets'."[92]

All of this begs another critical issue.

- What are UNSE's concerns for those with electrical life-support equipment that are NOT CARES-M customers?
- Does UNSE have any moral, ethical, and safety responses for these people? [this data request has not been responded by UNSE]

6.2 CARES Participation.

Table 13 shows 1,859 CARES participants in Santa Cruz and 4,130 CARES participants in the Mohave service areas. CARES eligibility is 150% of the Federal Poverty Level (FPL). As shown, Poverty (<100% FPL) varies between 13.9% to 24.5% and Working Poor (100 to 200% FPL) between 24.5% and 29.8% in each county. The 150% FPL population is not known,

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91 UNSE response to Magruder data request MM DRs 1.4c, 1.4d, 1.4e, and 1.4i.

92 UNSE response to Magruder data request MM DR 1.4j. If USNE does not know what a "check sheet" kind of response procedure involved, then its "Call Center" management personnel need basic training in effective contingency response processes. From other data, check sheets are required to be used by UNSE linemen for many contingencies.

however, splitting the difference between Working Poor and Poor is a very conservative number for the number of CARES-eligible customer who are NOT in the CARES rate program. The estimated number of CARES-eligible ratepayers NOT in this program are about 3,400 in Santa Cruz and about 9,900 in Mohave service areas. In the Santa Cruz area, about 65% of those eligible for CARES are NOT in the program with similar impacts in Mohave.

Table 13. Number of CARES Customers in Each County. *The number of Customers Eligible for CARES and the number on Potential CARES Participants.*

County / Poverty Status / Factors	Santa Cruz County		Mohave County	
	Poor (< 100% Federal Poverty Level)	**Working Poor** (100 to 200% federal poverty level)	**Poor** (< 100% Federal Poverty Level)	**Working Poor** (100 to 200% federal poverty level)
Total UNSE Customers in County	19,650		72,200	
Poverty Percent of the County	24.5%	29.8%	13.9%	24.9%
Number of Poor and Working Poor	4,814	5,699	10,035	17,977
Number of CARES participants[93]	1,859		4,130	
Percent of CARES eligible and participating in CARES	38.6%	32.7%	41.1%	22.9%
Number who are NOT participating in CARES	2,955	3,840	5,905	13,847
Half difference between 100% and 200% poverty level nonparticipants	~**3,397** CARES eligible and not in CARES program		~**9,876** CARES eligible and not in CARES program	
2007 CARES Qualifying Income at 150% Federal Poverty Level	Qualified for CARES is $2,581[94] a month or $30,975 a year (family of 4)			

6.3 CARES-M Participation.

As of March 2007, there are a total of 178 participants in the CARES-M program.[95] Between August 2003 and the end of 2006, the number of CARES-M participants in Mohave increased from 58 to 170 (193%) and in Santa Cruz from 1 to 10 (900%).[96] There has been a steady increase in CARES-M participants. Since there are unique CARES-M benefits with lower rates and avoidance of cut-off, it is important that this program be properly managed. As with the CARES program, all additional costs for these two programs are borne by the other ratepayers.

Q. What might cause this rapid rise in CARES-M participation?

A. The requirements to participate are that one has meet the income level, require life-support equipment, and, if requested, "submit a signed statement from the attending physician that the customer is medically-life support dependent and the type of essential medical equipment used

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[93] UNSE response to ACC Staff data request STF 3.2 Erdwurm UNS_ECustomerAdjustments.xls. spread sheet for June 2006, end of test year.

[94] UNSE response to Magruder data request MM DR 1.4f, CARES Application, Bates number UNSE(0783)0352) shows $2,500 a week for a family of four.

[95] UNSE response to ACC Staff data request STF 5.7.

[96] UNSE response to Magruder data request 1.4a.

at the residence."[97] A review of the application does not indicate the "type of essential medical equipment used" is required.[98]

6.4 Recommendations to Improve the CARES Program.

I concur with the proposed change in the CARES tariff.

In my opinion, I recommend that this program needs to be reviewed by a qualified, outside team with goals and objectives to (1) continue streamlining the application process, (2) increase background data verification to ensure ratepayer funds are used for those truly meeting the income levels, (3) do a media analysis for effectiveness (using data collection box numbers, etc.) and shift funds to higher performing media, and (4) that CARES participation rates be required to increase 10% a year until 75% of those eligible for CARES are included as CARES ratepayer, with targets of 35% on 1 January 2008; 45% on 1 January 2009, 55% on 1 January 2010, 65% on 1 January 2011, and 75% on 1 January 2012..

6.5 Recommendations to Improve the CARES-M Program.

I concur with the proposed change in the CARES-M tariff.

This program has some fundamental flaws which need management attention, as presently constructed, appears to have liability risk for the Company. This is a good program, which is just limping along without attention. Include CARES-M in with the program survey above for CARES.

It is recommended that the following actions be accomplished:

(1) All CARES-M Applications must be verified and validated at least annually to include equipment needs in terms of type of equipment, equipment manufacture and model number, frequency of equipment use and duration every 24 hours embedded battery back capability and estimated duration of operation on battery (if any), portability of this equipment, and a signed statement from the attending physician that states

> "This patient ______________ of mine is required to use ______________ equipment for life support and if this equipment is not operable for greater than ______________ (hrs/minutes), this patient will be in an unsafe condition.
> I understand that if this patient is not required to use this equipment for life support, I will nullify any prior statements with UNS Electric, Inc.
> If there changes in this statement I will also notify by phone or facsimile directly to the Company."

(2) A list of all CARES-M patients will be maintained at the Call Center, along with a "check sheet" of actions required to ensure the safety of all CARES-M and other non-CARES

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97 UNSE response to Magruder data request MM DR 1.4h.
98 UNSE response to Magruder data request MM DR 1.4f, CARES Application.

ratepayers on life-support equipment. This life-support check list will include for the patient's phone number and the local first responder's phone number. All ratepayers on life-support equipment (including non-CARES-M) will have their residences or locations mapped for rapid customer locational access. At least annually, UNSE will develop, host, conduct, and provide realistic training and feedback and lessons learned in a CARES-M ratepayer oriented drill or exercise. Results will be included in the appropriate reports to the Commission. Drills and exercises will be created by UNSE in collaboration with first responders and implemented throughout a county. The Call Center and County Emergency Management offices should be treated as key implementers for local life-support necessary for the safety of all customers requiring electricity-driven life-support equipment.

(3) UNSE will aggressively seek, identify, classify, and manage life-support information with its CARES-M databases for customers who are NOT in the CARES programs.

(4) All participants will have their records checked and physician statements renewed.

(5) Each County Emergency Management or Control Division will be provided with current ratepayers on electrical life-support equipment containing essential information in (2) above. The County will be requested to ensure communications and emergency response teams can meet the life-support requirements for these customers.

(6) UNSE will employ or obtain services of a medical life-support equipment specialist. This person shall be used to verify all CARES-M and other customers on life-support equipment. If and when a situation is deemed to be potentially fraudulent, additional expert advisor(s) or specialists should be readily available to assist UNSE in a supporting role.

(7) Because non-CARES ratepayers on life-support equipment have not been officially included in any UNSE such programs, it is recommended that a letter from top management be sent to all UNSE and UNSG customers informing all of the expansion of medical life-support and the CARES-M ratepayers, details about the program, and an application.

Part VII – ISSUE 5

Environmental Portfolio Standard (EPS) and Renewable Energy Standard and Tariff (REST) Surcharges

Q. Does UNSE have a Renewable Energy Program?

A. Barely, about 0.6% of what it is required to generate a year, which is also small, only 1.1% of its total retail sales. Again, this is 0.6% of 1.1%, which was 0.00646% of the total sales in 2006, the best year-to-date!

7.1 Reason for the EPS Surcharge.

Every ratepayer is presently required to pay a surcharge to fund renewable energy projects. The residential ratepayer has a monthly $0.35 surcharge on their bills. UNSE is required to use those funds as rebates for solar-electric, grid-connected systems or to purchase "green" power from appropriate sources.

Table 14 shows the required percent of the total power demand that is required by the Energy Portfolio Standard (EPS) as mandated by ACC Decision No. 67178. Actual data are shown before 2007. From this table it is obvious that the UNSE renewable energy program is a dismal failure. UNSE generated less than 0.6% (0.00646/1.05) of the required renewable power established for 2006. During the Test Year, the expenses incurred by UNSE to manage this program exceeded $33,330 for payroll ($27,880), marketing ($902), training and travel ($1,458), outside services and contracting ($2,923) and materials and supplies ($167). This program does NOT have ANY management attention at UNSE, but the public is demanding renewable energy, especially in Arizona, to sustain our national security, quality of life, and provide a healthy environment for the future. Obviously, UNSE's management does not share these goals, nor is UNSE or any UniSource entity ISO 14400 certified for Environmental Management, that forward-looking utilities have found very beneficial and cost effective.

Table 14. Actual Renewable Energy Generated to Date. *A total of 256 MWh of solar generate power has been generated since 1997. In 2006, the best year to date, only 0.00646% of the total UNSE load requirements, well below the 1.05% mandated by EPS, and was 16,818 MWh short.*[99]

Year	UNSE/Citizens Total Retail sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MW)	Actual Percent Renewable	Annual Renewable Deficit (MWh)
Column	(1)	(2)	(3)=(1)x(2)	(4)	(4)/(1)x100 (%)	(4)-(3)
>2001	NA	NA	NA	57.0	unknown	NA
2001	1,275,036	0.2 %	2,550	19.0	0.00149 %	-2,531

[99] This table used the UNSE response to ACC Staff data request 13.40, which included UNSE Test Year Annual Report on Environmental Portfolio Standard Programs, and UNSE response to ACC Staff data request 3.137, "Deferred Environmental Portfolio Surcharge Revenue Activity", Aug 2003 through Dec. 2006

Table 14. Actual Renewable Energy Generated to Date. *A total of 256 MWh of solar generate power has been generated since 1997. In 2006, the best year to date, only 0.00646% of the total UNSE load requirements, well below the 1.05% mandated by EPS, and was 16,818 MWh short.*[99]

Year	UNSE/Citizens Total Retail sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MW)	Actual Percent Renewable	Annual Renewable Deficit (MWh)
2002	1,136,581	0.4 %	4,546	19.4	0.00171%	-4,526
2003	1,392,466	0.6 %	8,355	13.3	0.00096%	-8,342
2004	1,462,633	0.8 %	11,701	10.0	0.00068%	-11,691
2005	1,631,947	1.0 %	15,210	26.7	0.00164%	-15,187
2006	**1,711,420**	**1.05%**	**16,919**	**110.6**	**0.00646%**	**-16,818**
subtotal	8,610,083	NA	59,281	256.0	NA	-59,095
2007e	1,659,763	1.10%	18,257			
2008e	1,709,555	1.10%	18,805			
2009e	1,760,842	1.10%	19,369			
2010e	1,813,667	1.10%	19,950			
2011e	1,868,077	1.10%	20,549			
2012e	1,924,120	1.10%	21,164			

Q. Where has all the EPS Surcharge money gone?

A. To the EPS Bank.

7.2 The UNSE EPS Bank.

Based on income from all customers paying the EPS surcharge, UNSE has been receiving $38,000 and $50,000 every month to support renewable energy programs. Most of these funds have gone into an EPS Bank which grows a few hundred thousand dollars a year, with a balance of $1,834,786 at the end of the test year on 30 June 2006.

Q. Has UNSE purchased any Renewable Energy?

A. Yes. Almost $1 million in "other" renewable energy. It has purchased Landfill Gas from TEP several times, in fact, during the Test Year UNSE purchased 6,000 MWh of Landfill gas and with this purchase will "carry a surplus of 1,981 MWh of 'other' credits into the second half of 2006."[100]

Date	Amount
December 2003	$200,000,00
January 2005	$131,502.17
December 2005	$159,000.00
September 2006	$290,255.92
December 2006	$173,250.00
Total	$954,008.09 for landfill gas from TEP[101]

[100] UNSE response to ACC Staff data request 13.40, Test Year EPS Report at 6.
[101] UNSE response to ACC Staff data request 3.137, "Deferred Environmental Portfolio Surcharge Revenue Activity"

Q. What has UNSE done in solar electric energy?

A. Some. In 1997, Citizens installed four solar-electric systems, with two at Lake Havasu City and two at Kingman, using DOE funds, which provided about half of the pre-2002 solar-electric energy. Each site has an output of approximately 4 kW, similar to the demands for a home. Both are grid-connected, without batteries. A total of 52 solar panels are involved, enough for two or so average homes. WOW! That is impressive and done so long ago. Citizens must have been a real leader back then. These systems used to generate 19 or so MWh per year but some components failed in 2003 and 2004 which reduced the total solar output in Table 14.

Q. Has UNSE had other systems producing solar energy?

A. As shown in Table 14, in 2004 the solar generated electricity leaped from 10 MWh to 26.7 in 2005 and to 110.6 MWh in 2006. During the Test Year, in Kingman, UNSE actually purchased 25.25 MW and in Lake Havasu City another 29.32 MW for a total of 54.58 MW. No solar electricity has been generated in Santa Cruz service area.

Q. How will be the future of ESP be transitioned to the new ACC Environmental Standard?

A. In November 2006, the Commission adopted a new environment standard, called Renewable Energy Standard and Tariff (REST) in ACC Decision No. 69127. Appendix A of this Decision contains the "rules" to implement REST.

7.3 Renewable Energy Standard and Tariff (REST) and UNSE.

Table 15 shows the REST requirements for 2006 to 2024 and beyond. This standard uses "credits" to account for renewable energy. In general, one REST credit equates to one MWh. The first year a utility is under the standard, the percentage of required renewable energy. This table uses the long-term UNSE generated requirements[102] in the second column, and estimates (e) for later years. The third column is the percentage of retail electricity sold that needs REST credits. The fourth column is the number of REST credits required for that year. The REST rules specify that some of the REST credits must be used for distributed generated electricity, using the percentages shown in the fifth column, while the sixth column are the annual REST distributed generation required. REST also required that residential REST credits must be at least half of the distributed generated energy, which is shown in the last column.

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[102] DeConcini Direct Testimony, Exhibit MJD-1, page 2.

Table 15. Some of the REST Requirements for UNSE.

Year	UNSE/Citizens Total Retail sales (MWh) Estimate	REST Percent Renewable Energy (%)[103]	Credits to meet REST (~MWhr)	Percent Distributed Generation (~MWh)[104]	Distributed Generated (~MWh)	Residential Generated (~MWh)[105]
Column	(1)	(2)	(3)=(1)x(2)	(4)	(5)=(3)x(4)	(6)=0.5x(5)
2006	1,631,000	1.25%	20,380	5%	1,119	555
2007	1,690,000	1.50%	25,350	10%	2,535	1,267
2008	1,790,000	1.75%	31,325	15%	4,699	2,345
2009	1,921,000	2.00%	38,420	20%	7,684	3,842
2010	2,022,000	2.50%	50,550	25%	11,333	5,566
2011	2,127,000	3.00%	63,810	30%	19,120	9,560
2012	2,234,000	3.50%	78,190	30%	23,457	11,728
2013	2.342,000	4.0%	93,680	30%	28,104	14,052
2014	2,449,000	4.5%	110,205	30%	33,061	16,530
2015	2,545,000	5.0%	127,250	30%	38,175	19,087
2016	2,629,000	6.0%	157,740	30%	47,220	23,610
2017	2,706,000	7.0%	189,420	30%	56,826	28,413
2018	2,760,000	8.0%	220,800	30%	66,240	33,120
2019	2,815,000	9.0%	253,350	30%	76,005	38,002
2020	2,872,000	10.0%	287,200	30%	86,160	43,080
2021	2,929,000	11.0%	322,190	30%	96,657	48,323
2022	No data	12.0%	380,000e	30%	1,140,000e	57,000e
2023	No data	13.0%	445,000e	30%	1,335,000e	66,750e
2024	No data	14.0%	510,000e	30%	1,530,000e	76,500e
2024+	No data	15.0%	560,000e	30%	1,680,000e	84,000e

7.4 Recommendations to Convert ESP Surcharge to a REST Surcharge/Adjustor.

Based on the present performance of UNSE in obtaining, using, and adding renewable energy generation equipment to its portfolio, UNSE will have to "catch-up" as the 260 MWs generated in 2006 falls far short of 20,380 MWh of REST credits required.

The following are **<u>recommendations</u>**

(1) That UNSE invigorate its "Green Watts" program, which was upgraded and expanded by ACC on 21 December 2006.

(2) That UNSE present an implementation plan to the Commission prior to 1 January 2008 showing how UNSE will be on track with the requirements of REST by 1 January 2010.

(3) That UNSE commence implementation of sample tariff REST surcharge, within the first billing cycle 30-days after Commission approval of this docket.

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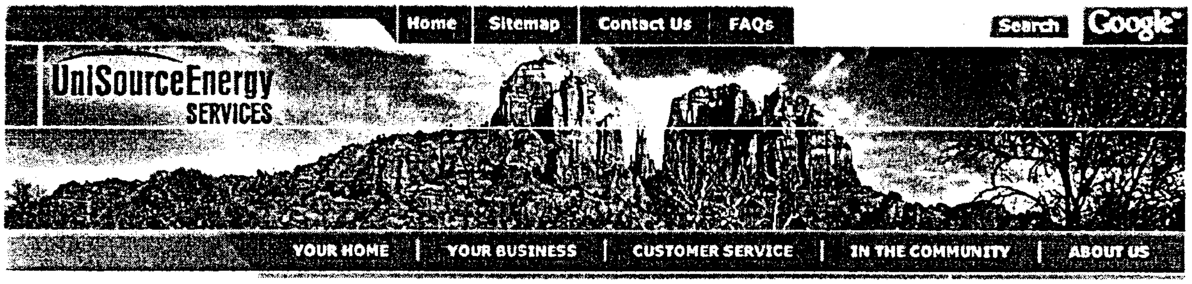
[103] ACC Decision No. 69127, Appendix A, R14-2-1804.B, page 11.
[104] *Ibid.*, R14-2-1804.F, page 13.
[105]

Exhibit B

Enclosure B-3, UNSE Payment Agents



Customer Service

- Account Manager
- Account Services
- Billing & Payment Options
  - Payment Options
  - Courtesy Payment Box Location
  - Cash Payment Agent
  - *UES e-bill*
  - Pricing plans
  - Budget Billing
  - SNAP
  - GreenWatts
  - Warm Spirit
  - Bill Inserts

Customer Service

Payment Agents

- ACE Cash Express Locations
- Additional Cash Only Locations

$$$ - Cash only -

- You will be provided with a receipt after cash payment has been made.
- Please verify the accuracy of your account number on your receipt before leaving.
- Please take your bill stub with you. This will help make sure your payment is processed accurately.
- A $1.00 fee will apply at selected locations (see below).

ACE Cash Express Locations

Bullhead City

1812 Highway 95, Ste 20, Bullhead City, AZ 86442
(928) 763-8865
($1.00 fee will apply)

Store Hours: Monday through Thursday 8:30 a.m. to 6:30 p.m.; Friday 8:30 a.m. to 7:00 p.m.; Saturday 9 a.m. to 5 p.m.; Closed Sunday

Camp Verde

522 Finnie Flats Road, #F, Camp Verde, AZ 86322
(928) 567-0676

Store Hours: Monday through Friday 9:00 a.m. to 6:00 p.m.; Saturday 9:00 a.m. to 3:00 p.m.; Closed Sunday

Chino Valley

1578 N. US-89 Suite A, Chino Valley, AZ 86323
(928) 636-5545

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Cottonwood

989 S. Main, Ste B, Cottonwood, AZ 86326
(928) 639-1000

Store Hours: Monday through Friday 8:30 a.m. to 6:30 p.m.; Saturday 10:00 a.m. to 5:00 p.m.; Closed Sunday

Golden Valley

52 S. Hope #A1, Golden Valley, AZ 86431
(928) 565-5055
($1 fee will apply)

Store Hours: Monday through Thursday 10 a.m. to 6:00 p.m.; Friday 10 a.m. to 7 p.m.; Saturday 10:00 a.m. to 2:00 p.m.; Closed Sunday

Kingman

3787 Stockton Hill Road, Kingman, AZ 86401
(928) 692-7110
2785 Northern Ave, Kingman, AZ 86401

Account Manager

E-mail:

Password:

LOGIN

New user?
Learn more | **Enroll**

Forgot your password?

Tell a friend

What's New

UES e-bill

UES e·bill

RECEIVE • VIEW • PAY

SIGN UP TO RECEIVE, VIEW AND PAY YOUR UES BILL ONLINE.

LEARN MORE

Energy Advisor

ANALYZE YOUR HOME OR BUSINESS ENERGY USE. LEARN WHERE YOU CAN SAVE MONEY!

LEARN MORE

Safety

STAY AWAY AND STAY ALIVE. STAY AWAY FROM DOWNED POWER LINES.

LEARN MORE

(928) 757-7575
($1 fee will apply)

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Lake Havasu City

20 N. Acoma Blvd, Lake Havasu City, AZ 86403
(928) 854-4447

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Nogales

1965 N. Grand Ave., Nogales, AZ 85621
(520) 761-3999

Store Hours: Monday through Saturday 9:00 a.m. to 9:00 p.m.; Sunday 10:00 a.m. to 6:00 p.m.

570 W. Mariposa, Nogales, AZ 85621
(520) 377-2013
($1 fee will apply)

Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Sunday 9:00 a.m. to 4:00 p.m.

43 N. Morley Ave, Nogales, AZ 85621
(520) 287-7400
($1 fee will apply)

Store Hours: Monday through Saturday 10:00 a.m. to 6:00 p.m.; Sunday 10:00 a.m. to 4:00 p.m.

Prescott

621 Miller Valley Road, Prescott, AZ 86301
(928) 777-0039

Store Hours: Monday through Thursday 8:00 a.m to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Prescott Valley

8101 E. Hwy. 69, Ste A, Prescott Valley, AZ 86314
(928) 759-9939

Store Hours: Monday through Thursday 9:00 a.m. to 6:30 p.m.; Friday 9:00 a.m. to 7:00 p.m.; Saturday 9:30 a.m. 5:00 p.m.; Closed Sunday

Additional Cash Only Locations

Flagstaff

OA Quick Cash
3470 E. Route 66, Suite 101, Flagstaff AZ 86004
(928) 526-5626
Store Hours: Monday through Friday 9:00 a.m. to 5:30 p.m.; Saturday 10:00 a.m. to 2:00 p.m.; Closed Sunday

Winslow

Winslow Document Express
118 B E. Second St., Winslow AZ
(928) 289-3290
Store Hours: Monday through Friday 9:00 a.m. to 5:00 p.m.; Closed Saturday and Sunday

Show Low

Audio Advantage/Radio Shack
4431 S. White Mountain Rd., Suite 1, Show Low AZ 85901
(928) 532-0462
Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Closed Sunday

Sedona

Weber IGA Food & Drug
100 Verde Valley School, Sedona AZ 86351
(928) 284-1144
Store Hours: Monday through Saturday 6:00 a.m. to 10:00 p.m.;

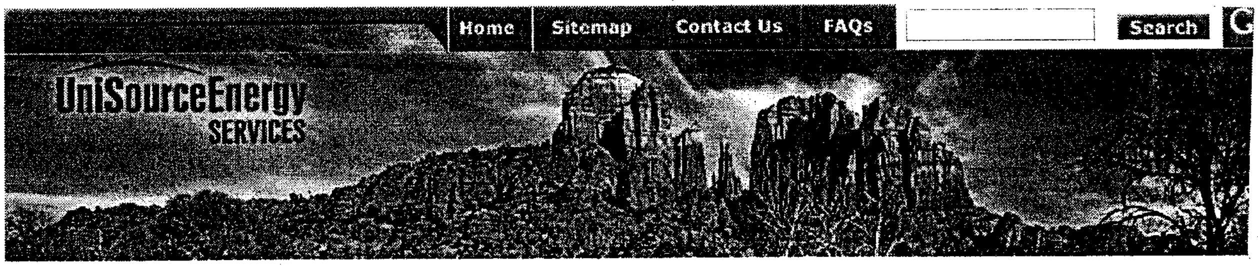
from page 3 of 3

Sunday 6:00 a.m. to 9:00 P.M.

07/09/2007 12:18 AM

Exhibit B

Enclosure B-4, Credit and Debit Card, and Bank Withdrawal Application



This payment service is provided by a third party payment processor for electric customers of UniSource Energy Services. The payment processor will add a convenience fee of $3.95 for every $250 to the total amount of the payment. You will be given an opportunity to accept or decline the payment after the total amount is calculated.

Order Information:

Payment Date: 7/9/2007

UES Account Number (Electric): [ ] (Example: 7831092)

Please enter your account number as shown on your bill

Enter Payment Amount: $ [ ]

Customer Information:

Customer Name: [ ]

E-mail Address: [ ]

Pay From:

○ **Debit Card** ○ **Bank Account** ○ **Credit Card**

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BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
M-24
Admitted

COMMISSIONERS
Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC.

Docket No. E-04204A-06-0783

Notice and Filing of the

Surrebuttal Testimony

of

Marshall Magruder

24 August 2007

As provided by the Procedural Orders of 1 February 2007, 27 March 2007, and 25 June 2007, herein is the Surrebuttal Testimony of Marshall Magruder.

My Direct Testimonies concentrated on five issues: the Demand-Side Management (DSM), administrative issues, cost to improve reliability, CARES and CARES-M, and Environmental Portfolio Standard/Renewable Energy Standard and Tariff programs.

This Surrebuttal Testimony responds to the UNS Electric Rebuttal Testimonies.

I certify this filing has been mailed to all known and interested parties, as shown on the Service List, by email on 24 August 2007, and by US mail as soon as possible thereafter.

Respectfully submitted on this 24th day of August 2007

MARSHALL MAGRUDER

By Marshall Magruder

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PO Box 1267
Tubac, Arizona 85646-1267
(520) 398-8587
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Service List

Original and 17 copies of the foregoing are filed this date by email and by mail as soon as feasible afterward with:

Docket Control (13 copies)
Arizona Corporation Commission
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SURREBUTTAL TESTIMONY

OF

MARSHALL MAGRUDER

24 August 2007

**In the matter of
the**

**APPLICATION
OF UNS ELECTRIC, INC.,
FOR THE APPROVAL OF THE
ESTABLISHMENT OF JUST AND REASONABLE
RATES AND CHARGES
DESIGNED TO REALIZE A
REASONABLE RATE OF RETURN ON THE
FAIR VALUE OF THE PROPERTIES OF
UNS ELECTRIC, INC.**

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SURREBUTTAL TESTIMONY OF MARSHALL MAGRUDER

PART I – INTRODUCTION

1.1 Introduction.

Q. Why are you filing this surrebuttal testimony?

All intervening parties are required to file their Surrebuttal Testimony on or before 24 August 2007. This Surrebuttal Testimony responds to the UNS Electric (UNSE) Rebuttals of 14 August 2007 and others.

1.2 Summary of Issues and Recommendations.

Q. Can you summarize the issues from your Direct Testimonies?[1]

A. Several issues of concern are in my testimonies as follows:

Issue 1 – Demand-Side Management (DSM) Program.

Issue 2 – Administrative Issues

Issue 3 – Costs to Improve Electric Reliability in the Santa Cruz service area.

Issue 4 – CARES and CARES-M Tariffs

Issue 5 – Environmental Portfolio Standard (EPS) Surcharge and Renewable Energy Standard and Tariff (REST)

Each issue received some comments in UNS Electricity's Rebuttal Testimonies; however, only a few of the recommendations in my Testimonies received any comments. A few were rejected by UNSE; however, the basis for most of those was weak and unsupported by evidence or by reference. In UNSE Rebuttal Testimonies, all 18 of the footnotes were in areas that my Testimonies did not discuss.

Q. Can you summarize your recommendations in responding to UNSE's Rebuttals?

A. Yes. My recommendations have not been changed in most cases and vary for each issue.

Issue 1 Recommendations – There are different recommendations for each DSM Program.

- Education and Outreach DSM Program. My detailed Recommendations are in my Direct Testimony in 3.2.f with the cost changes summarized in Table 1 that added $273,205 to the 2008 Cost Budget. I recommend change the title to "DSM Education and Training Program" to integrate performance, information and knowledge.

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[1] These two testimonies are The Direct Testimony of Marshall Magruder, of 26 June 2007, hereafter as "**Magruder Direct Testimony**" or "**my Direct Testimony**" and the The Supplemental Direct Testimony of Marshall Magruder, of 12 July 2007, hereafter as "**Magruder Supplemental Testimony**" or "**my Supplemental**" and for both, hereafter as "**Magruder Testimony**".

- Direct Load Control DSM Program. My detailed Recommendations are in 3.3.f of my Direct Testimony, in 3.3 in my Supplemental and herein. My serious concern and potentially life-threatening structural flaws were not accepted by UNSE. This must be resolved by UNSE before implementation and any determination of program cost.
- Low-Income Weatherization DSM Program. My detailed recommendations are 3.4.f of my Direct Testimony and 3.4 in Supplemental to delete $5,104 from proposed budget.
- Residential New Construction DSM Program. My detailed recommendations are in 3.5 my Direct Testimony and 2008 with proposed budget changes to delete $21,924.
- Residential HVAC Retrofit DSM Program. My detailed recommendations are in 3.6.f of my Direct Testimony and 2008 with proposed budget changes to delete $27,954.
- Shade Tree DSM Program. My detailed Recommendations are in 3.7.f of my Direct Testimony and herein to removal of this DSM program. This deletes all funds ($65,000) in the budget because overhead cost greatly exceeded customer benefits. A $30 tree rebate coupon should not have $35 of overhead to administer. UNSE still supports.
- Commercial Facilities Efficiency DSM Program (EE). My detailed recommendations are in 3.8.f of my Direct Testimony and the 2008 budget to expand customer participation and add $93,289 to the proposed budget.
- The proposed 2008 DSM Budget recommended totals $3.428.000; however, by reducing all programs 25% but excluding LIW, the recommended 2008 DSM Program is now $937,430 with an aggregated DSM Adjustor rate for all customer is 0.00057966 per kWh in 3.9 my Supplemental and this Surrebuttal.

Issue 2 Recommendations. The detailed recommendations are in 4.1 of my Direct Testimony, Supplemental, and herein. Many Administrative recommendations are to modify billing schedule changes, eliminate using predatory loan and check cashing facilities as UNSE Billing Agents, revise the billing statement, and changes to the UNSE Rules and Regulations. Most were unanswered any UNSE's Rebuttals.

Issue 3 Recommendations. The detailed electricity reliability in Santa Cruz service area recommendations are in 5.4 of the Supplemental to delete of $15,561,520 from the UNSE rate base for failure to comply with ACC Orders, to complete and continuous compliance with the City of Nogales and ACC Staff Agreements, to avoid expenses performed prior to acquisition credited to UNSE, to increase access on WAPA transmission lines with significant customer savings when compared to TEP transmission lines, to be consistent with operational objective measures, to comply with NERC-WECC reliability for substation data management, to commence actions required for a second transmission line and to not just rebuild a single circuit line, and to cease "fear ,mongering" about how soon the "lights will go out" in Nogales.

Issue 4 Recommendations. The detailed CARES and CARES-M recommendations are in 6.4 and 6.5 of my Supplemental Testimony, with new human safety concerns for life-support equipment for non-CARES-M ratepayers during an outage.

Issue 5 Recommendations. The detailed recommendations for transition from EPS to REST have been revised in this filing in 7.2 below.

1.3 Recommendations for additional Issues.

Q. Are there additional issues that others have included or time does not permit testimony?

A. Yes. Other areas of concern, including some from the Magruder Motion to Intervene, that may still be resolved before or during the forthcoming evidentiary hearings:

a. *Mandatory* Time of Use (TOU) tariffs for new residential and small commercial ratepayers, This should not be a mandatory program and the **highest 15-minute period** used for calculation of the "demand" in not reasonable, that is 1/16th of the peak period and 1/48th of the off-peak period in summer, I recommend that a one-hour period or more be used.

b. Proposed Purchase Power and Fuel Adjustment Clause (PPFAC) rate structure includes the Test Year energy losses. UNSE in its response to my Data Request refused to provide this data and stated energy loss costs were not appropriate for this case. Ratepayers in the PPFAC pay the energy losses based on last test year. Quantification of energy loss from 2005-2006 test year results must be clearly presented by UNSE.

c. New purchase power, generation and transmission agreements impacts on ratepayers were requested but not received, as they are "confidential", so they cannot be reviewed.

d. Prudency of its *present* DSM Program since the last rate case. There has been very little "bang" for the "bucks" invested in the present DSM Program.

e. Reliability concerns and planning cost for a second Nogales substation, The single Nogales substation is in the100-year floodplain and is greatly overloaded and crowded,

f. Effectiveness of the ACC *Environmental Portfolio Standard* since the last rate case,

g. Potential for any Citizens-UniSource transition of ownership costs to be absorbed by the customers beyond those in the Settlement Agreement,

h. Potential for UNS Electricity, Inc. ratepayers to pay multiple or imprudent charges to UniSource Energy and its subsidiaries including increases in O&M and G&A, and,

i. Conflicts and higher expenses for customer meters are being replaced by two different programs that appear totally un-integrated, the TOU and DSM DLC programs, which appear redundant meter changes as one meter should be used for both programs to make this more efficient.

Some of these issues were not presented due to discovery issues and/or refusal to respond. UNSE unilateral deemed such information was not appropriate. I did not want to delay these proceedings and request assistance of the ALJ even though I could use this capability that was available for all parties.

PART II – ISSUES

2.1 Summary of Issues

Q. Can you summarize the issues from your Direct Testimonies?

A. The issues of concern included in my testimonies and continue in this response to the applicant's rebuttal testimonies. I have numbered them for convenience.

Issue 1 – Demand Side Management Programs, see Part III

Issue 2 - Administrative Issues (Billing Schedules, Predatory Loan/Check Cashing Facilities as Billing Agents, Revised Billing Statement, and R&R Publication) in Part IV

Issue 3 – Cost to Improve Electricity Reliability in Santa Cruz County in Part V

Issue 4 - CARES and CARES-M Tariffs in Part VI

Issue 5 – Environmental Portfolio Standard (EPS) **Surcharge and Renewable Energy Standard and Tariff** (REST) in Part VII

2.2 Impacts of these Issues on proposed UNS Electric rates or procedures.

Q. Do any of these issues impact overall proposed capital cost or changes?

A. Yes. Each issue will have different changes and impacts, if the recommendations are approved. A brief summary of these changes include:

Issue 1 – DSM Programs. The recommended changes impact the scope and expenses proposed for each proposed DSM Program. Based on these changes, the aggregated summation of the DSM Surcharge Adjustor rates for each program directly impact the resultant rates for all UNS Electric ratepayers.

Issue 2 – Administrative Issues. The recommended changes impact areas that are not directly related to company's expenses but directly impact the customers.

Issue 3 – Cost to Improve Electricity Reliability in Santa Cruz County. The recommended changes will remove some capital expenses from the test year, which impact rate base due to failure to meet agreements in ACC Orders.

Issue 4 – CARES and CARES-M Tariffs. The recommended changes have minor impacts on expenses as additional safety/administrative procedures are recommended.

Issue 5 – EPS and REST Surcharge/Adjustor. The recommended changes include deletion of the EPS Surcharge; implement an interim Renewable Energy Standard and Tariff (REST) and REST Bank until USNE obtains approval of a new REST Surcharge/ Adjustor in a separate case, and for failing to meet the existing EPS Goals.

PART III – ISSUE 1

DEMAND-SIDE MANAGEMENT PROGRAMS

Q. What is the status of testimonies concerning these DSM programs?

A. In a few words, continual confusion and lack of clarity, which I will discuss first in general and then specifically for each proposed DSM program.

3.1 UNS Electricity Demand-Side Management Programs.

On 13 June 2007, UniSource Energy Services (UES), for UNS Electricity, Inc., filed with ACC Docket Control, a letter[2] that was the basis for my Direct Testimony on 26 June (13 days later). Since that filing, additional information continues to come forth in various data request responses and the UNSE Rebuttals, which are now included here.[3] This Surrebuttal clarifies the concerns, primarily from Ms Smith's UNSE Rebuttal.[4]

Before going into those concerns, it was noted the UniSource Energy Services (UES),[5] UNSE holding company, a non-party to these proceedings, sent a letter dated 13 June 2007. This letter has not been filed until UNSE Rebuttal, which the D. Smith Rebuttal "incorporated herein by reference."[6] Further, the 13 June 2007 letter did not state, "UNS Electric filed its comprehensive DSM Program Portfolio *to replace* [emphasis in original] the original filing on December 15, 2006."[7] This letter stated "The Company is fling the enclosed Portfolio so that details regarding the DSM programs can be considered in a <u>separate</u> proceeding (the "DSM Docket")" with "general DSM testimony in its ongoing rate case in"[8] this docket. In my view, this lacks any real clarity as to, even now, any real legal status for this letter, and uncontested.

There have been no Commission comments on these series of confused, overlapping, and conflicted filings, known by this party (other that the Procedural Order in this docket, about considering DSM for the 12 July 2007 Direct Testimony filings). This confusion is in both UNSE and UNSG dockets concerning DSM Surcharge Adjustor determination, DSM

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[2] UNSE letter "Re: UNS Electric, Inc.'s Demand Side Management Program Portfolio Filing, E-04204A-07-_____", of 13 June 2007, hereafter "**UNSE DSM Programs**", at 2.

[3] In particular additional program information in the "Rebuttal Testimony of Denise Smith on Behalf of UNS Electric, Inc." of 14 August 2007, hereafter "**D. Smith Rebuttal**".

[4] *Ibid.* page 2, lines 18 to 21. The draft DSM document "ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1, Draft Demand-Side Management Rules," of 7 February 2005, hereafter "**Staff DSM Report**" was used extensively in my review of the UNSE DSM Programs; with only minor deviations due to the age of that first draft and major technological DSM changes and emphasis in the past two years. If given a chance, updated approaches, such as subsequently recommended by ESRI, will produce more effective results and benefits.

[5] The role of UES in this case and in UNSE DSM Programs is a mystery.

[6] UNSE DMS Programs, first paragraph of cover letter.

[7] D. Smith Rebuttal, page 3, lines 24 and 25.

[8] UNSE DMS Programs, first paragraph of cover letter.

Program approval, and which of these two precedes the other. This is not a Company decision but is an ACC procedural issue open for interpretation in the "separate' and uncoordinated TEP, UNSG, and UNSE ongoing rate cases. Each defines unique DSM Surcharge Adjustors to impact all ratepayers in three independent public service companies.

It is inconceivable rates could be increased with a DSM Surcharge Adjustor prior to (1) any decisions concerning acceptability, accountability, prudency, or accomplishments planned for these DSM programs; (2) the two UNSE and UNSG parties roles and (3) interactions with TEP (if any), the ACC Staff, and RUCO reviews and comments for each DSM program; and (4) computation and the apportionment of DSM Surcharge Adjustor "rates" to customer categories for each Company. All of these procedural actions must be resolved prior to first approval of the DSM Surcharge Adjustor rate.

Individual DSM Programs required review and approval before assessing customers. My testimony, considers many areas where significant adjustments are essential prior to charging ratepayers. The UNSE Testimony shows the DSM Surcharge Adjustor will be charged as a function of electricity consumed for all rate categories, with no emphasis equally on individual customer or rate category consumption reductions. These interactive DSM programs have assumed an equally function of consumption but not demand reduction function goal and objectives. Demand-Side Management requires "demand" goals, objectives, and plans on how and by what processes to achieve specified and Commission-approved "demand" goals in MW and MWh for power and energy for its customers and Company's benefit. An Example of what needs to be considered, assessed, and resolved.

Only Lake Havasu City residential and some small commercial customers will be involved with the Direct Load Control DSM program however all ratepayers will fund it without any possibility of participating, thus.

a. Is it reasonable and fair that all UNSE customers fund this limited (or any other specific) program) with no opportunity to participate?
b. Should all rate categories, some of which may never have Direct Local Control (DLC), be charged the same DSM Surcharge Adjustor rate for this DLC DSM program?
c. Do the specifics of this (or other) DSM program meet the Commission plans for DSM?

Q. What is your attitude and expectations for the long-term DSM results for UNSE?

A. I strongly support DSM and its three components, energy conservation, energy efficiency, and demand response.[9]

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[9] Magruder Direct Testimony, pages 16 line 28 to page 17 line 12, in 3.1.1. One reason for these definitions are to clarify the extreme confusion that now exists so that clear, objective, separations exist between these three terms and that subsequent regulatory proceedings, hearing, order and decisions are consistent when

There is also the fourth component, *dynamic response* that is considerably more advanced beyond the existent capabilities at TEP or UNSE.[10] Dynamic Response not recommended for consideration at this time.

ESRI estimates range from 10-25% of total U.S. electricity consumption" can be reduced by energy efficiency. This is significant. ESRI believes regulators [ACC] need to use this potential and "elevate its strategic priority'."[11]

UNSE Rebuttal commented that the energy efficiency terms and definitions used in my Testimonies did not agree with a draft DSM document.[12] I agree and said so when presented. This "first draft" UNSE reference is over two years old and has not yet been approved by the Commission, I used a more common definitions of the first three components the Department of Energy (DOE) used in its DSM website, where

a. Energy Conservation (**EC**) is voluntary and has no customer cost (but has benefits) and is not readily measurable,
b. Energy Efficiency (**EE**) involves using equipment or things (such as higher R-rated insulation for walls) that have a cost to reduce electricity consumption, and
c. Demand Reduction (**DR**) uses "controls" to selectively reduce consumption.

This discussion shows the boundary definitions of the "draft" terms are not clear definitions.

Q. Can you explain your DSM program changes recommended in your previous filings?

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it comes to "money" differences that are clear between these terms as I have defined them. DOE used these definitions in its DSM discussions but I am unable to locate that reference at this time.

10 There is an excellent background paper which came to light after my Supplemental Testimony, by the Energy Power Research Institute (ESRI) and is found on its website, "Advancing the Efficiency of Electricity Utilization: "Prices to Devices", 2006 EPRI Summer Seminar," which defines in its Executive Summary

- **Energy Efficiency** consists of ongoing technology development and programs in energy efficiency driven by economic and policy drivers. In this sense, these drivers result in a built-in improvement in energy efficiency that is occurring on an ongoing basis. This area has a large and direct bearing on CO_2 reduction as well as related electricity consumption.
- **Demand Response** represents shifting the pattern of the load. This area has a small impact on energy reduction but is a large role in enhancing systems economics and reliability. It may or may not result in reduced CO_2.
- **Dynamic Systems** represents the future of networked, smart, end-use devices interacting with the marketplace for electricity and other consumer-based services. Market interaction includes sending direct "prices to devices[SM]." This area may have substantial impacts on system reliability, customer value, modest energy savings, and CO_2 savings."

Energy Conservation was not defined but usually includes voluntary measures only to reduce energy consumption. I intend to introduce this Executive Summary during the testimonial hearings.

11 *Ibid.*

12 D. Smith Rebuttal, page 2, lines 18 to 21. The Draft ACC DSM Report was used extensively in my review of the UNSE DSM Programs, with only minor deviations due to the age of that first draft and major technological DSM changes and emphasis in the past two years. If given a chance, updated approaches, such as subsequently recommended by ESRI, will produce more effective results and benefits.

A. Certainly. Seven DSM programs are now proposed by UNSE. Each is independent of the others but all have common goals and objectives. They are discussed, with responses to UNSE Rebuttal.

a. Education and Outreach (Training and Education) Program in 3.2 below
b. Direct Load Control Program in 3.3 below
c. Low-Income Weatherization Program in 3.4 below
d. Residential New Construction Program in 3.5 below
e. Residential HVAC Retrofit Program in 3.6 below
f. Shade Tree Program in 3.7 below
g. Commercial Facilities Efficiency Program in 3.8 below and
h. The resultant and aggregate DSM Surcharge Adjustor rate in 3.9 below

In 3.2 to 3.8 of my Testimony, each DSM program is discussed in terms of its proposed scope, references, requirements, verification, and recommended improvements with 3.9 used for aggregated data derivation of the SDM Surcharge Adjustor rate. My Testimonies use the paragraph numbers above to ease tracking.

Q. Are there general concerns raised by the UNSE you would like to respond?

A. Yes. In general, the UES DSM Programs letter has a cover letter and seven DSM Program Attachments. There is no DSM integration plan that ties all these programs into a unified plan with goals and defined objectives and thresholds. I added 3.9 to integrate aggregating costs necessary to determine the proposed DSM Adjustor Surcharge for all future customer billings.

I recommend a DSM integration plan include a summary of each DSM Program's goals and objectives, to include commonality throughout implementation and to centralize cost accounting information. An expansion of 3.1.1 and Table 1 from my Direct Testimony[13] show the relationships between these programs in one location and in my Supplemental, Table 2 how each program's costs lead into the total DSM Adjustor Surcharge rate.[14] Further, general DSM program guidance must be provided and assumptions in repetitive parts of the individual DSM Programs.

Q. What is your reaction to UNSE concerns about reporting more environmental impacts?

A. Not until the UNSE Rebuttal was information known about the method for calculating environmental impacts. It now appears that a simple, single cycle natural gas turbine is the reference. In reality, most electricity generated in Arizona and used by UNSE is from coal-

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[13] Magruder Direct Testimony, 3.1.1 pages 16 and 17; Table 1, page 17, Types of Demand-Side Management for the Seven Proposed UNS Electric DSM Programs.

[14] Magruder Supplemental Testimony, Table 2, page 18, Summary of Proposed DSM Costs for UNSE DSM Programs and DSM Adjustor.

fired steam turbine generators, which have significantly more pollutants than natural gas. UNSE must use relevant data applicable to UNSE and not TEP (with 90% coal) or APS.

Q. What should be used as the environmental impact reference model(s)?

A. For simplicity, I recommend using a 50:50 split between natural gas and coal-powered generation, to reflect the fuel diversity in the UNSE service area. This basic information should be included in the UNSE DSM Programs documentation. A traceable, UNSE-relevant, and conservative approach for determination environmental impacts is desirable.

For natural gas, the nameplate or documented reference environmental data for the BMGS, being procured by UNSE, values could be used. These values are not known by this party but should be easily available to UNSE. If not feasible, using the environmental impacts from the new LM-2500 natural gas turbine fuel in Nogales would be appropriate. Realistic, UNSE-oriented environmental impact assessments are essential for truth in these values.

For coal-generated, there is no standard. Data for the new 1,500 MW Desert Rock power plant has been published. This is intended to be one of the "cleanest" coal generated plants in the United States. Using the environmental impacts for the plant should remain conservative as indicated in the UNSE Rebuttal.

Based on the "Department of Interior Preliminary Technical Comments on the Desert Rock Prevention of Significant Deterioration (PSD) Permit Application" (September 2006),[15] the following are the annual pollution emission limitations required for these two 750 MW boilers using supercritical pulverized clean-coal are:

Sulfur Dioxide (SO_2)	3,315 tons per year$_2$
Nitrogen Oxide (NO_x)	3,315 tons per year
Total Particulate Matter (PM_{10})	1,105 tons per year
($PM_{2.5}$)	unknown
Sulfuric Acid Mist	221 tons per year
Hydrogen Fluoride (HF)	13.3 tons per year
Mercury emissions	114 lb per year
Ozone	unknown
Water consumed	unknown

The DSM Program impacts must use specific and objective environmental parameters, and I recommend, the ratio of the above emissions be a function of the annual MWh of UNSE r annual sales, as a minimum, in associated reporting. UNSE should obtain and publish the "unknowns" and ratios necessary for computation. Thus, I recommend the UNSE environment

[15] I intend to bring copies this document to the evidentiary hearings for ACC Staff and UNSE.

impact statistics look more like the below Table A. This expands that originally recommended and provides a much better and more honest, conservative, and comprehensive display for each and all DSM programs:[16]

Table A – Environmental Impact Factors for UNSE DSM Programs.

GHG, Airborne Pollutants and Others	Saved [Pounds]	Other Environmental Impacts	Saved [various units]
Carbon Dioxide (SO_2)		Water Saved	gallons
Sulfur Dioxide (SO_2)		Mercury Emissions	ounces
Nitrogen Oxide (NO_x)			
Total Particulate Matter (PM_{10})		Additional TBD Impacts	TBD
Total Particulate Matter ($PM_{2.5}$)			
Sulfuric Acid Mist			
Hydrogen Fluoride (HF)			
Ozone (O_3)			
Total			

With this more complete list of environmental benefits, UNSE and ACC should be able to report more complete information to the public, Arizona Department of Environmental Quality (ADEQ), US Environment Protection Agency (EPA) and others interested.

Q. Can you respond to UNSE comments with respect to the Citizens Advisory Council?

A. Yes. In the D. Smith Rebuttal paragraph B.1; the first topic is "Citizens Advisory Council". This Rebuttal missed the point concerning the ACC-mandated in ACC Order No. 61793 of 29 June 1999, that the CAC, was in the City of Nogales-Citizens Settlement Agreement[17] The CAC was formed to improve future electricity service and as consumer and business communications mechanism to improve a very negative attitude prevailing, including the abrupt termination of the City of Nogales franchise Agreement. The CAC was to open communications and dialog between this utility and the local citizens on a continuous basis to reduce the probability of the prior unpleasant experiences. The Company is required to have a CAC so relevant issues, which specifically included DSM in the ACC Order, are openly discussed. The CAC last met in September 2000. The second transmission line issue has not been resolved as claimed. TEP missed its mandated operational date of 31 December 2003,

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16 For an example, see Magruder Direct Testimony, page 21, lines 14 to 18, but recommend that a standard table be used in for each program in a report, but as additional environmental information becomes available that this information be discussed in the Report Summary section and then used.

17 Please see Magruder Supplemental page 22 line 10 through page 30 line 8 for additional discussions on this and the subsequent ACC Staff-Citizens Settlement Agreement with page 24 line 19 to page 25 line 6 for details concerning CAC. Also, see Part V of this filing.

or earlier. The Company obtained a waiver of the $30,000 month penalty for liquidation of damages for missing this "critical date or the lights will go out" deadline Mr. Glaser COO for TEP personally testified before the Commission that he would not miss this operational date for any reason. He is retired and we see another promise not kept.

Q. Can you respond to UNSE comments with respect to multiple DSM programs?

A. Yes. The D. Smith Rebuttal in B.2, the second topic was concerned about "lost revenue" or "lost net revenue," used at least four times in the UNSE DSM Programs This was misunderstood in the Rebuttal. My comments concerned UNSE and any recovery as "avoided costs"[18] or recovery of revenues that were "lost" revenue due to DSM consumption savings It is noted only the Commission could make that decision; not the ACC Staff. Commissioners, using ACC Staff through, comprehensive and validated recommendations can make the Commission decision. The public must be notified, informed, and have an opportunity to comment on changes to the DSM Adjustor Surcharge impacts on rates. My concern had nothing to do with cost-benefit tests but with ACC Staff versus Commission and the lost revenue issue.

The third topic in B. Smith Rebuttal in B.2 discusses changing the cost-effectiveness methodology established by the Commission in the Staff DSM Report. For each program in my testimonies, the "societal test benefit effectiveness" was provided directly from the UNSE DSM Programs document, if there were recommended changes that would invalidate the value from the UNSE DSM Programs description documentation. UNSE societal benefits test ratios were used and not "calculated" differently. In many cases, oblivious statistical analysis was used. For example, in on program the UNSE cost to administer and provide rebates for the "shade tree" program, based on UNSE data, were $35 per tree for a $30 benefit per participant. This is not a "new" or non-conformant calculation, but an obvious fact. Common sense should always be a part of any "judgment" that uses all factors when making decisions. The Rebuttal missed these points.

The fourth topic in the D. Smith Rebuttal in B.2 discusses "line loss" used in DSM calculations. They did not match today's line lost values. This Rebuttal indicated that the Commission has not approved a new line loss in this case. In fact, I have been unable to obtain the 2005/2006 Test Year Line Loss data as Mr. Beck in data request responses has stated that line loss in not relevant to these hearings. Since the PPFAC presently equals wholesale price plus the cost of line loss, which uses the last Test Year line loss values that also impacts correct DSM calculations. The line loss values in my Testimony are the correct

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[18] Magruder Direct Testimony, on page 27 line 8 footnote 38; page 28 line 25 footnote 41; page 29 line 28 footnote 50; and page 36 line 5 and footnote 71.

values from the last rate case. The line loss in the Residential HVAC DSM Program was 10.69%. There is an additional 4.95% line loss for the WAPA transmission lines for a total of 15.64%, the line loss used for the current PPFAC.

Q. Does this complete your response to general DSM issues?

A. Yes.

Q. Could you respond to UNSE concerns about the "Education and Outreach" Program?

A. Yes. I will briefly describe this program, our differences, and recommendations in 3.2.

3.2 Education and Outreach DSM Program or DSM Education and Training Program.[19]

Each program should have independent goals and objectives of the others; however, the Education and Outreach Program should be expanded to provide all the external media exposures, training and marketing support for all UNSE DSM Programs. This integration of information sharing benefits from one DSM program impacts other DSM programs and facilitates centralized DSM training management, courseware development, media campaigns, and should lower costs with cross-functional activities by personnel working in this program. This combination of training and education efforts should produce synergy between UNSE employees, contractors, call center, and most importantly, provide a united "face" to the customers. As now constructed, with education and training fragmented, conflicts may arise and best customer-focused programs overlooked by contractors making money from UNSE.

Unfortunately, the D. Smith Rebuttal overlooked the recommended $318,205[20] for the DSM Education and Training Program. This has no budget problems as integrated training and education element consolidated and retained all the proposed training and education costs.

Ms Smith discussed the current ACC "first draft" definitions for Demand Side Management elements, discussed above in detail. Her "belief" about "energy efficiency" would be solved with more definitive and the DSM element definitions I recommended with supporting references. Since the draft ACC DSM Policy is NOT approved, these definitions are the only variance from the ACC Staff's first draft, discussed openly in my Testimonies, so "The Commission will make the final recommendation". I agree and see no problem here.

Q. Do you want to change any of your DSM Training and Education Recommendations?

A. The D. Smith Rebuttal accepted recommended items 1.b, 3 and 4, which is appreciated. The additional recommended items 1.a, 1.c, 2, 5, 6.a, 6.b, 6.c, 6.d, 6.e, 6.f, 7, 8, 9, 10, 11, 12, 13,

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[19] UNSE DSM Plan, Attachment 1 – Education and Outreach Program. A new Title "DSM Education and Training Program" has been recommended as a better title for this program.

[20] Magruder Supplemental Testimony, pages 13 and 14, Table 1, "Recommended Program Cost Summary for DSM Training and Education Programs for Implementation in 2008," and page 18, Table 2, "Cost of Proposed and Recommended Cost of UNSE DSM Programs with DSM Adjustor"

14, 15, 16, 17, and 18, as expanded in my Supplemental Testimony with 2008 funding recommendations, were not in the UNSE Rebuttal.[21] They remain valid recommendations.

The UNSE final comment about "UNS Electric is unable to provide 15-minute interval data without the use of AMI/AMR" is true. I agree and fully support replacing all analog meters with two-way automated meters. I recommended, as DSM elements are developed, planned and implemented and mature, then inclusion in the DSM Training and Education Program is logical and should be incrementally incorporated during the DSM Program Annual updates. I fully support combined TOU/DLC automated, two-way meters for every UNSE customer with remote data displays and control features so that UNSE "smart" meters are fully interoperable with the Intelligent Grid (see the ESRI Intell-Grid) making both micro- and macro- real-time information and knowledge available at ALL levels from the customer to the UniSource CEO to the ACC Staff to the Secretary of Energy. This has to be done, one-step at a time with eyes open and the long-term vision clear of chaos, or failure and lost revenues follow.

Without any rebuttal comment for these and all other recommendations, other than a temporal delay for item 7, I can then assume all of these numbered recommendation items are acceptable for future UNSE implementation and for consideration and recommendations to the ALJ for consideration in the resultant ACC Order.

Further, UNSE is concerned about performance measures for DSM Training and Education Programs, which are "energy conservation" programs that are hard to measure in terms of kW and kWh from personal behaviors. I completely agree with her concern, which is why the definition for all these "energy conservation" items are subjective, with sparks of genius sometimes lighting objective measures. Energy Conservation is a DSM element with its own performance measures, such as indicated by Ms Smith, but is needed to be defined appropriately in the Second Draft ACC Staff DSM Report and the final version presented to the Commissioners.

Q. Does this complete your response for the "DSM Training and Education Program"?

A. Yes.

Q. Could you respond to the UNSE concerns about the "Direct Load Control (DLC) DSM Program"?

A. Yes. I will briefly describe this program, our differences, and recommendations in 3.3.

3.3 Direct Load Control (DLC) DSM Program.[22]

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[21] Magruder Supplemental Testimony, page 12 line 5 to page 14 line 13, including Table 1, Recommended Program Cost Summary for DSM Training and Education Program for Implementation in 2008"

[22] UNSE DSM Programs, Attachment 2, "Direct Load Control (DLC) Programs"

I appreciate the work that Ms Smith has done in updating me on the status of the Florida Power and Light DSM program. My referenced FPL DSM program was its R&D effort for about 800,000 customers, of which over 700,000 voluntarily participated, received rate rebates and participation was free. I read the analysis of its 50% OFF cycle timing with horror for residents of Lake Havasu City, one of the hottest locations in the United States,[23] vastly exceeding anything in Florida, where 100F is rarely experienced. As my conclusion (2) stated this is "hazardous" and recommendation item 3 that a shorter OFF cycle time than 50% in the proposed location is a critical safety issue. Some customers have air conditioning systems that, at temperatures over 100F or so, are on 100% of the time and still not able to "cool" anymore. If shut off, temperatures will rise even more and we will see a small-scale French August disaster when 15,000 died due to heat. Manufactured homes are especially vulnerable due to lack of insulation and metal walls and roofs, especially older retirees, many times used as the "best affordable" retirement home for the thousands of elderly in Lake Havasu City. The Company cannot tell them to purchase more air conditioning equipment, which is not affordable for these customers. Without a careful audit of the "envelope" and air conditioner outputs, messing with this situation will expose UNSE to liabilities that are not reasonable just due to this high of OFF cycle percentage. If "dynamic systems" (as defined earlier) were available, then this kind of cycle time might be reasonable since some residences have adequate or even excess cooling capacity.

My comments about 15 minutes off per four hours was from the FPL R&D program results and going over 50% is, in my view, for Lake Havasu City still not safe and will be hazardous for some UNSE customers. As a minimum a human health hazard risk analysis should to be accomplished, not a "cost-effectiveness" analysis, before any recommendation greater than 12.5% OFF cycle should be considered for this area. UNSE **Cost** effectiveness, should intuitively have superb results for Lake Havasu City using a 50% demand reduction cycle in this ultra-hot city where air conditioning is probably more important than any other City in Arizona, Without air conditioning, Lake Havasu City would not exist.

Cost is <u>ALWAYS</u> less important than human safety.

Q. Do you want to change any of your DSM DLC Recommendations?

A. Upon review of the Rebuttal shows acceptance of Recommended item 1 and is appreciated, Recommended item 2 is OBE.

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[23] While driving to Kingman, AZ on 19 August 2007, the radio reported the temperature at Lake Havasu City was 116F.

Recommended item 3 was rejected by UNSE's Rebuttal. Item 3 is now recommended more strongly than my prior understanding. The UNSE Rebuttal is for 50% cycle OFF. The 3 or 4 hours per day or 100 hours per year are insignificant compared to consecutive or near consecutive OFF air conditioning cycles.

Recommended Items 4.a, 4.b, 4.c, 4.d, and 4.e and 5 should be considered only if proven to meet the cost-effectiveness test. When two or more electrical equipment are combined for one customer then cost-benefit tests should be at the customer level (more DR per meter), than for any one individual demand-reduce energy sources. This 'whole customer' approach should be considered for cost-effectiveness, or certain customer benefits if 2, 3, 4 or 5 of a list of 5 items are placed under DLC DR schemes.

Recommended Items 4.f and 7 to revise the DLC "draft" Participation Agreement "after" DLC receives Commission approval for implementation" is a bad business practice that opens the Company for later liability issues. It is noted that draft "Participation Agreement" does not state 15-minutes so the participant unknowingly agrees when signing the agreement to jeopardize their life? Convert this agreement to English/Spanish-Friendly wording. Change to include real-time "telephonic" changes as stated in its description in UNSE DSM Programs.[24]

Recommend item 8 concerning "off-the-shelf, proven equipment and DLC hardware and software" was rejected with rationale that shows the immaturity of the UNSE team in this area. Systems engineering practices are essential for hardware and software requirements analysis, systems trades, system synthesis, system design, system and component tests, installation and operations and maintenance, and retirement phases, All require integration. For example, this approach does even not mention the associated TOU meter requirements that will be deployed to a far greater extent than these DSL meters. Does UNSE have a Strategic Automated Meter Plan, or equivalent? UNSE system-level smart metering implementation will determine the future of this distribution utility and its profit potential through smart and knowledgeable system design. The "Commission" should never restrict this Company's strategic planning or determine internal integration elements, unless the Commission has a "vision" to integrate all Arizona utilities with an Intelligent Grid, such as ESRI's IntelliGrid, which requires "smart" meters integrated throughout the state. This vision must be sound, forward looking and non-restrictive for the utilities. The MOST restrictive

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[24] UNSE DSM Programs, Attachment 2 at 5 states "Participant will have the right at any time to over-ride a specific control event by notifying UNSE in writing or by telephone. Participant will have the right at any time after the first year to terminate the service by notifying UNSE in writing or by telephone." [Note, "in writing" during a four-hour control event is not realistic.]. This statement is not in Appendix 1 (DLC Participant Agreement) and contradicts paragraphs 9 and 21.

decision would be the use of "proprietary" hard/software by any utility. Open Systems, open architectures, industry standard all work, closed systems have no future.

Recommended item 9 follows the UNSE process used to determine the DSM Adjustor however was ignored by UNSE's Rebuttal

Q. Does this complete your response to "DSM DLC Programs"?

A. Yes. The Supplemental Testimony discussion concerning Time of Use is valid, but may change if the "super" TOU schedules in Alternative B are approved. However,[25] Supplemental Testimony Figure 1 (rev) now shows when TOU and DLC control actions[26] can both occur including proposed Peak (A) and Super-Peak (B) winter alternatives described in the caption.

Time of Day / Month	00-1AM	1-2 AM	2-3 AM	3-4 AM	4-5 AM	5-6 AM	6-7 AM	7-8 AM	8-9 AM	9-10 AM	10 11	11 12	12-1PM	1-2 PM	2-3 PM	3-4 PM	4-5 PM	5-6 PM	6-7 PM	7-8 PM	8-9 PM	9-10 PM	10-11	11-12
January							A	A	A	A								A	B	B	B			
February							A	A	A	A								A	B	B	B			
March							A	A	A	A								A	B	B	B			
April							A	A	A	A								A	B	B	B			
May													S	S	P	P	P	P	S	S				
June													S	S	P	P	P	P	S	S				
July													S	S	P	P	P	P	S	S				
August													S	S	P	P	P	P	S	S				
September													S	S	P	P	P	P	S	S				
October													S	S	P	P	P	P	S	S				
November							A	A	A	A								A	B	B	B			
December							A	A	A	A								A	B	B	B			

DLC May-Sept

DLC 1 to 8 P.M.

Figure 1 (Rev). DLC Action Events and Time of Use (TOU). *This figure shows that DLC events will occur between May and September and from 1 PM to 8 PM in the Box with arrows. Peak Hours are shown with P (red), Shoulder with S (yellow), and Off-Peak (green) are blank. In the winter, there are two evening alternatives under consideration, Alternative A includes all the hours shown with as A and B (A+B), and the Super Peak Alternative B with the three hours indicated by B.*

Q. Could you respond to UNSE concerns about the "Low-Income Weatherization DSM Program"?

A. Yes. I will briefly describe the differences and resultant recommendations in 3.4.

3.4 Low-Income Weatherization (LIW) DSM Program. [27]

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[25] Rebuttal Testimony of D. Bentley Erdwrum on Behalf of UNS Electric, Inc., 14 August 2007, hereafter "**Erdwrum Rebuttal**", page 11, line 8 to page 12 line 1.

[26] The months and hours that DLC actions might occur are from UNSE response to Data Request STF 13.32 of 18 June 2007. The UNSE Rebuttal, by several witnesses, proposed reducing the winter Peak Hours from eight to three hours, now referred to as "super peak" with alternatives being recommended, therefore specific winter evening peak hours under Alternative A are as originally proposed and the super peak as Alternative B. [Erdwrum Rebuttal page 11 and Exhibit DBE-2]

[27] UNSE DSM Programs, Attachment 3, "Low-Income Weatherization (LIW) Program"

The UNSE Rebuttal agreed that the $2,552 under CARES billing war in error and it should have been under the budget entry for "rebate processing." This is agreeable with this party so the resultant budget for this program remains as proposed.

Q. Do you want to change any of your LIW DSM Program Recommendations?

A. Yes. The UNSE Rebuttal only discussed Recommended item 2 about the Rebate Processing change from CARES Billing.

No changes to Recommended item 1 other than added additional environmental reporting elements. Recommended item 3 is now OBE due to no change from the proposed budget. Recommended item 4 remains which has been discussed previously.

Q. Could you respond to UNSE concerns about the "New Construction DSM Program"?

A. Yes. I will briefly describe any differences and resultant recommendations in 3.5.

3.5 Residential New Construction DSM Program a.k.a. Energy Smart Homes (ESH) (EE). [28]

UNSE is concerned that the return to customers was stated in conclusion item 1 as 38.4%. This is not as error. This conclusion considered only the "DIRECT" rebates to customers, with no overhead. UNSE considered support plus customer rebate as benefit to agree with an overall return to customers at 58% for 2008. This no changes are necessary as this conclusion Item 1 emphases direct to [LIW, which should read ESH] participants. "Direct" is even underlined in this conclusion item statement for this purpose and emphasis.

In addition, UNSE is concerned that the goals recommended are too high.

Q. Do you want to change any of your ESH DSM Program Recommendations?

A. No changes are recommended; however, UNSE seemed concerned about reducing overhead recurrent costs. I remain very concerned. UNSE should and must continually be striving to reduce all costs at all levels of the Company. These DSM Programs are not a corporate-welfare program but defined customer-benefit program, similar to Company's benefits, where cost containment is always critical. Reducing all costs is always a valid recommendation.

The UNSE Rebuttal would like to take a more conservative approach than in Recommended Item 2 for increased participation. To resolve this, I have seen both "minimum" and "target" and "stretch" used for "minimum" and "highly desired" achievement requirements. This, would recommend for 2008, a "target" of 15% for 2008 and "stretch" goal of 45% for 2008, with the likely result being halfway in between. Annual revisions of these two should be, as suggested by UNSE, in their DSM Reports and DSM Annual Reviews.

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[28] UNSE DSM Programs, Attachment 4, "Residential New Construction Program"

Recommended item 3 use the UNSE process (nothing new in the process was used) to calculate DSM Surcharge Adjustor rate.

Q. Does this complete your response to ESH DSM Program"?

A. Yes.

Q. Could you respond to UNSE concerns about the "Residential HVAC Retrofit DSM Program"?

A. Yes. I will briefly describe any differences and resultant recommendations in 3.6.

3.6 Residential HVAC Retrofit DSM Program.[29]

UNSE is concerned that subcontractor and internal marketing budget expenses have been deleted from this program budget. The $12,000 internal marketing expenses were not deleted, but as discussed in the DSM Training and Education DSM Program, transferred to that program. Contractors, subcontractors, and company employees can and frequently work on integrated teams that will benefit information sharing, make the organization more productive/efficient and produce "team" results to benefit the customers. In other industries these are called Integrated Product Teams (IPTs) which are "product" or, in this case, program-oriented objective performance tasks, doing the same tasks with others doing similar tasks, using similar training facilities and equipment and common tools and processes. Unfortunately, UNSE is not ISO 9000 certified, thus is unaware of process management, improvement and self-correcting process performed by process mature companies.

Subcontractor Expenses of $35,952 are not appropriate. UNSE is self-managing this program. No subcontractor expenses are necessary. UNSE expenses in all areas remain as proposed. See Table 4 in the Magruder Direct Testimony for these "subcontractor" expenses.

This program's total budget an <u>additional $20,000</u> for 17 and 18 SEER air conditioner-heat pump rebates. UNSE DSM Programs does not provide any rebates to these most efficient air conditioners and heat pumps. The Rebuttal does not want any incentives. Further, UNSE Rebuttal would only escalate above $100/ton for 17/18 SEER units "if the Commission wishes." The Company should be active and propose not wait for such obvious direction over a logical decision. As a minimum, $100/ton is more reasonable than $0 for the most efficient air conditioners on the market, and the kinds of units The Solar Store in Tucson recommends be installed to reduce solar electricity capital costs.

UNSE is concern reporting savings in "therms" violates the "fuel neutrality" clause in the "first draft" ACC Staff DSM Report. Savings of any/all forms should be reported, including

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[29] UNSE DSM Programs, Attachment 5, "Residential HVAC Retrofit Program"

"therms" which has been included by UNSE for the "Residential New Construction Program" in 3.8 below. The "therms" do not have to be used in the "cost benefits analysis" but should be recorded to benefit and/all accomplishments by UNSE in its DSM Program.

Q. Do you want to change your Residential HVAC Retrofit Program Recommendations?

A. No. UNSE was concerned about the $12,000 internal marketing budget transfer and deletion of subcontractor expenses when a subcontractor does not exist remain.

Recommended items 2 and 3 add new 17 and 18 SEER incentives, as none exist now, and continue to report saved "therms," if and when applicable.

Recommended item 3 remains as is.

Thus, no recommended items were changed.

Q. Does this complete your response to "Residential HVAC Retrofit DSM Program"?

A. Yes.

Q. Could you respond to UNSE concerns about the "Shade Tree DSM Program"?

A. Yes. I will briefly describe any differences and resultant recommendations in 3.7.

3.7 Shade Tree Program.[30]

Q. Do you agree with the UNSE Rebuttal comments on the energy and demand savings value the proposed "Shade Tree Program?

A. No.

Q. Does the UNSE Rebuttal disagree with Mr. Magruder's Direct Testimony?

A. Yes. The UNSE Rebuttal indicated the Magruder Supplemental stated UNS Electric "does not have an assessment of the impact of reducing loads or energy savings through shading from trees."[31] UNSE Direct Testimony stated "UNSE does not currently have a baseline assessment of the applications of trees to reduce cooling loads, nor an estimate of the energy savings potential of reducing cooling loads through shading from trees."[32] The quote is from UNSE DSM Programs "Shade Tree Program" and confirms to my Supplemental Testimony.

The UNSE Rebuttal cites Appendix 3 of the Shade Tree Program which is for "Trees of high shade yield, medium to large sized."[33] This assumption is erroneous because the two trees selected, native, local Palo Verde and Mesquite, are NOT "trees of high shade yield". Non-native, non-local trees are prohibited by a Santa Cruz County Ordinance.

a. Palo Verde. From an Arizona poster there is an excellent description of Palo Verde,

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[30] UNSE DSM Programs, Attachment 6, "Shade Tree Program"
[31] D. Smith Rebuttal, page 20, lines 8 to 10 and Magruder Supplemental, page 33.
[32] *Ibid.* page 1 under Current Baseline Conditions.
[33] *Ibid.* Appendix 3, "Measure Analysis Worksheet," page 12, lower left corner.

> "The 'Palo Verde' (genus *Cercidium*) is Arizona's state tree. The name means 'Green Stick' in Spanish. During much of the year these trees are leafless, the green bark of the trunk and branches takes over the function of photosynthesis."[34]

b. Mesquite. See my Direct Testimony for non-qualifying factors for this tree.[35]

Further, the Shade Tree Program contains energy savings data with faulty assumptions, for non-qualifying "shade tress" have a benefit/cost ratio of 1.07 with a payback in 0.4 years. This fails any "common sense" test for reasonableness.

A 15-gallon tree is not medium to large sized as assumed in Appendix 3. A 15-gallon tree will cost at least $100 per tree to have a backhoe dig the hole to plant (calicle clay below the soil prevents digging with a pick and shovel), $15 or more for mulch per tree, and at least 15 or more years of water to mature while increasing the fire hazard each year.

The $35 overhead expenses for a $30 coupon are ridiculous and a waste of ratepayers' funds. This fails all prudency test considerations.

A larger overhanging roof or porches on East, South, and West sides prevents sun from reaching walls and windows.[36]

As stated in both my Direct and Supplemental Testimonies, cost greatly exceeds benefits for this program and is the primary reason for rejection. If overhead costs were less than $5 per coupon, which is still excessive, this program might have some merit as a corporate marketing effort and not chargeable to ratepayers but not as a ratepayer-funded DSM program.

The UNSE Rebuttal made my negative recommendation even stronger. This is an unworthy program without UNSE ratepayer benefits worth but a fraction of the high UNSE administration costs.

Q. What is your response to the UNSE Rebuttal about "field verification" of shade trees?[37]

A. Apparently UNSE misunderstood my testimony that stated this program "has a repeated and not relevant section on Monitoring and Evaluation. It is not expected that UNSE field

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34 Waldmire, Robert, "A Poster of Arizona," Springfield IL: Frye-Williams Press, ca 1985.

35 Magruder Direct Testimony, in paragraphs 3.7(1) on pages 34 and 35, also in 3.7e(2) on page 35, the fire danger is discussed. The mesquite is especially prone to "shedding" branches and limbs during periods of drought as a way to reduce its water needs. These dead branches are very dry and flammable, thus to be FIREWISE, they should not be planted within 30-feet of homes, especially in rural areas, where wild fires are a significant and real treat.

36 My home was designed to have various energy efficiency measures that include a 10-foot porch around the south and west walls and over 50% of the east wall to keep sun off walls and windows during periods when solar radiation is highest. In the winter, when the sun's declination is below the Equator, sunrays reach the South wall and near winter solstice, rays reach the lower part of my southern windows, with minor warming benefits. Trees can be unnecessary for energy efficient designed homes.

37 D. Smith Rebuttal, page 20, lines 18 to 27.

personnel will check customer's yards to verify UNSE 'shade trees'."[38] I NEVER expected any "field verification" would even be considered for such a program. The Rebuttal comment for repeated statement for "field verification" of shade trees is a waste of manpower and financial resources for a $30 rebate coupon. The UNSE Rebuttal went to great length to justify because the "first draft" ACC Staff DSM Report required "field verification", thus "UNS Electric will conduct field verification of the installation of a sample of measures throughout the implementation of the program" is an example of blindly following a "first draft" rule instead of requesting another way or a waiver for this program. This fails the common sense test.

Field verification will be nearly impossible to verify if "that tree" is the tree that a rebate coupon was requested, approved and sent to a ratepayer so the tree can be purchased, hole dug, planted, watered and the tree lived. What about the 30% not expected to survive, do they have to be verified? Wow, all for a $30 coupon! If this program is deleted, as recommended, this waste of MY DSM Adjustor payments will be eliminated. It should go for a "real" program.

Q. Do you have any other responses to this "Shade Tree Program"?

A. Yes. The UNSE Testimonies and DSM Plan includes two statements:

a. "If community projects wish to take advantage of incentives to plant trees, UNSE would not object."[39]

b. "Desert-adapted trees will be provided to residential neighborhoods, public areas, and schools by UNS Electric base upon an application with interested community agencies or marketing by retailers."[40]

This says the UNSE Shade Tree Program will supply trees to

(1) Neighborhoods,
(2) Public areas,
(3) Schools,
(4) Interested community agencies or
(5) Marketing by retailers.

NONE meet the specified requirements in the Shade Tree Program "Delivery Strategy and Administration".[41]

How can UNSE justify using the ratepayers DSM Surcharge Adjustment fees for ANY of these 5 (or more) distributions. The "or more" is inserted because one implementation

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[38] Magruder Direct Testimony, in paragraph 3.7d, on page 34, under Program Performance Measurement.
[39] UNSE DSM Programs, Attachment 7, Program Concept and Description", page 1.
[40] Ferry Direct Testimony, page 21, lines 6 to 11.
[41] UNSE DSM Programs, Attachment 7, pages 2 and 3, and Appendix I, page 6.

model steps states "UNSE modify the Shade Tree program as necessary"[42] This does not require Commission approval.

This program, used for years by TEP, is a corporate "marketing' program that is trying to obtain ratepayer funding. The TEP rules are unknown, but this one for UNSE fails.

Q. Do you want to change your "Shaded Tree Program" Recommendations?

A. **No.** The UNSE Rebuttal states "UNS Electric believes the Shade Tree program provides significant energy and environmental benefits to customers." This "belief" just is not true."[43]

The UNSE "Shade Tree Program" is <u>not recommended</u> for DSM Surcharge Adjustor ratepayer funding. IF the company wants to distribute "trees" or "coupons" to any of these five (or more), that is fine, but <u>not</u> at ratepayer expense as none qualify under this program.

Q. Could you respond to the "Commercial Facilities Efficiency DSM Program" concerns?

A. Yes. I will briefly describe any differences and resultant recommendations in 3.8.

3.8 Commercial Facilities Efficiency DSM Program.[44]

UNSE is concerned that I assumed all participants receive the maximum rebate in Conclusion item 1. This was used for illustrative purposes and in no way was intended to limit this, the best DSM program proposed, as I recommended additional participation and funding. There was no discussion of an incentive "cap to prevent one or two customers from consuming the entire" program budget.

In response to providing copies of proposed proposals, agreements and report formats for this program, UNSE stated, "these have not been developed but will be in the coming months for the Commission approval." Does this imply the UNSE DSM program, which is on the "fast track" for Commission review and approval will be delayed until UNSE completes basic program information required for approval?

Q. Do you want to change your "Commercial Facilities Efficiency DSM Program" Recommendations?

A. No. My five recommendations are valid and remain as in my Testimonies. In my opinion, this is a <u>best</u> DSM program being presented in the UNSE DSM Plan.

Q. Do you have any responses to UNSE's concern about the DSM Surcharge Adjustor?

A. Yes. Each program's DSM Surcharge Adjustor factor equals the ratio of the Test Year total energy load in kWh[45] divided by the DSM Program Cost for the year. The sum of each DSM

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[42] *Ibid.* Appendix 1, page 6, Implementation Model.
[43] D. Smith Rebuttal, page 21, lines 1 to 6.
[44] UNSE DSM Programs, Attachment 7, "Commercial Facilities Efficiency Program"

Program's DSM Adjustor factor equals the annual DSM Surcharge Adjustor rate for ratepayers. All ratepayers will be assessed at the same DSM Adjustor rate for the year. Each year, this should be repeated, using the above process, and, after review and approval by the Commission, the next years DSM Surcharge Adjustor rate implemented for all ratepayers. This process must be clear, verifiable, and transparent.

During each year, USNE will report the details to monitor each DSM Program, the derivation of the program's semi-annual cost, and for the end of the year, the Total DSM Program financial and performance results. If excess DSM revenue is collected from the effective DSM Surcharge Adjustor, this excess is subtracted from the next year's cost for that DSM Program, before calculating the next year's DSM Surcharge Adjustor factor.

During the semi-annual DSM program ACC Staff reviews, USNE should be required to report at least the semi-annual cost-to-date for each DSM program and if the cost minus revenue will positive or negative for each program. All excess DSM funds should be expended in the next year's DSM Surcharge Adjustor process above. If USNE has overspent (negative excess), the ACC Staff should recommend how UNSE will compensate for overspending to the Commission during the Annual DSM Review for a decision.

Further, when any claims for lost revenue are made "the Commission shall determine whether a utility may be allowed to recover lost net revenue"[46] by the Commission during the Annual DSM Review. In addition, the utility will probably reduce its expenses based on the results of various DSM Programs. The reduction must be considered by the Commission during each Annual DSM Review. Any expense savings by the Company should be an important decision factor when the Commission determines the Annual DSM Surcharge Adjustor rate.

Q. Do you have any changes to your Recommended DSM Adjustor Surcharge?

A. Yes. The return of $2550 in the LIW program was removed due to a reporting error by UNSE. Table 2 (Rev) reflects the DSM Adjustor with this correction.

3.9 DSM **Summary of DSM Costs and Recommended DSM Adjustor Surcharge.**

The proposed and recommended 2008 cost for each DSM program with the calculated DSM Surcharge Adjustor factors for that DSM Program are in Table 2(rev). It also shows the total cost for the USNE DSM Programs and recommended DSM Surcharge Adjustor for each recommended DSM program.

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[45] The Test Year total energy was 1,606,376,387 kWh from UNSE Response to ACC Staff data request STF 13.14.

[46] ACC Staff's First Draft of Proposed DSM Rule, Exhibit 1, Draft Demand-Side Management Rules, R14-2-1709.B which states "The Commission shall determine whether a utility may be allowed to recover lost net revenue."

Table 2 (Rev). Cost of Proposed and Recommended Cost of UNSE DSM Programs with the DSM Surcharge Adjustor.

DSM Programs for 2008	Proposed (3)		Recommended (3)	
	Program Cost (100%)	DSM Adjustor[47]	Program Cost (100%)	DSM Adjustor
DSM Education and Training (1)	$170,000	0.00010517	$318,205	0.00019809
Direct Load Control DSM Program	1,968,000	0.00122512	1,843,000	0.00114730
Low-Income Weatherization DSM Program (2)	105,000	0.00006536	99,896	0.00006225
Residential New Construction DSM Program	420,000	0.00026146	398,076	0.00024781
Residential HVAC Retrofit DSM Program	300,000	0.00018676	272,046	0.00016935
Shade Tree Program	65,000	0.00004046	0	0.0
Commercial Faculties Efficiency DSM Program	400,000	0.00024901	493,289	0.00030708
Total	$3,428,000	0.00213334	$3,424,512	0.00213188

Note 1. The title was changed, as recommended to ensure DSM funding for ALL Education & Training activites are in this program.
Note 2. Add $2,550 to program to Recommended program cost.
Note 3. The Proposed and Recommended Program Costs are 100%. Company requested 25% of costs plus 100% of the LIW.

If the Proposed 2008 Program was implemented, the 2008 DSM Adjustor rate would be 0.00213334 so UNSE could recapture the total cost of $3,428,000 in the second column.

If the Recommended 2008 Program is implemented the 2008 DSM Adjustor rate would be 0.00213188 so to recapture the total cost of $3,424,512 in the fourth column.

UNSE requested first year DSM Surcharge Adjustor to fund 25% of DSM Programs except LIW is funded at 100% for a study and DSM Program Surcharge Adjustor start later.

Using this formula, the Proposed cost for the 2008 DSM Program is **$935,750** [(total/4 + 3xLIW/4)] (857,000+78,750). The Proposed DSM Surcharge Adjustor rate is **0.00058236** (0.00053333+0.00004902),

The Recommended 2008 Program Cost is $934,878 (856,128 + 78,750) + $2,550 for the LIW Program = **$937,428.** The Proposed Cost of the 2008 DSM Program was $950,000.

The Recommended 2008 DSM Surcharge Adjustor rate is **0.00057966** (0.00053297+0.00004669) per kWh. The proposed DSM Surcharge Adjustor rate was 0.00059 per kWh.[48]

Q. Does the complete your DSM testimony.

A. Yes.

[47] DSM Adjustor is calculated using same method in the UNSE Response to ACC Staff data request STF 13.14, by dividing cost by the test year adjusted kWh 1,606,376,397.

[48] Direct Testimony of James S. Pignatelli on behalf of UNS Electric, Inc., of 15 December 2006, hereafter "Pignatelli Direct Testimony" at 15.

Part IV – ISSUE 2

ADMINISTRATIVE ISSUES

Q. Are there any changes to this group of administrative Issues?

A. No. There are several sub-issues, and for clarity, identified as follows:

a. Sub-Issue 2.1, Changes in "Connect" Fees (deleted earlier)

b. Sub-Issue 2.2, Billing Schedules

c. Sub-Issue 2.3, Predatory Loan/Check Cashing Facilities as Billing Agents

d. Sub-Issue 2.4, Revised Billing Statement

e. Sub-Issue 2.5, R&R Publication.

4.1 Rebuttal Testimony Responses to these Administrative Issues.

Sub-Issue 2.1 – Not at issue in this UNSE case (deleted)

Q. Do you have any responses related to Mr. Ferry's Rebuttal Testimony on Billing?

A. Yes, however he did not respond to my Testimonies. Let me discuss the issue then respond.

Sub-Issue 2.2 – Billing Schedule.

UNSE proposed to reduce the time between Bill Due and Termination to "avoid confusion for customers served by both UNS Electric and UNS Gas."[49]

a. The Company's proposal is to change the interval from Bill Due to Delinquent from 15 days to 10 days.[50] A review of A.A.R., R14-2-210.C.1 states "All bills for utility services are due and payable no later than 15 days from the date of the bill. Any payment not received within this time-frame shall be considered delinquent and could incur a late payment charge." This is a unique interpretation of the A.A.R.

b. The Company's proposal is to change the interval from when a Bill becomes Delinquent to the start of the Termination Process from 7 days to 5 days.

c. The Company issues a "Suspension of Service Notice" 15 days after the bill is rendered. The A.A.R. does not discuss a "Suspension of Service Notice," only a "Termination Letter". If they are the same, the proposed Timeline below for Termination becomes 20 days instead of 25 days, a 12 day reduction from the 37 days after billing to termination.

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[49] Rebuttal Testimony of Thomas J. Ferry on Behalf of UNS Electric, 14 August 2007, hereafter "**Ferry Rebuttal**" page 2,

[50] Direct Testimony of Thomas J. Ferry on Behalf of UNS Electric, 15 December 2006, hereafter "**Ferry Direct Testimony**," Exhibit TJF-1, relined page 82, Section 11.C.1, which states. All bills for electric service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time frame will be considered past due." [underlined were the changes, "fifteen (15)" and "shall" in original]

d. It is possible for a customer to have their service terminated as early as 20 (or 25) days after the Bill is mailed and also due, which can very between 25 and 35 days after prior bill. Within a ten day billing window, and a twenty day schedule, customer financial planning for monthly wage checks becomes very challenging for lower-income ratepayer.

THE PRESENT TIMELINE OF BILLING EVENTS:

Day -1 to 0	Meter is read, reported to the Company (between 25 and 35 days after prior reading)
Day 0	Billing Date, when the bill is rendered (considered when mailed), the Bill is Due
Day 15	(15 days after Due) Bill is Past Due
Day 25	(10 days after Past Due) Bill is Delinquent, Payment Penalty starts[51]
Day 30	Late Penalty (1.5%/month) starts for all account balances 30 days after postmark of account bills
Day 32	(7 days after Delinquent) Termination Process begins
Day 37	(5 days after Termination letter is mailed, Earliest Termination

THE PROPOSED TIMELINE OF BILLING EVENTS:

Day -1 to 0	Meter is read, reported to the Company (between 25 and 35 days after prior reading)
Day 0	Billing Date, when the bill is rendered (considered when mailed), the Bill is Due
Day 10	(10 days after Due) Bill is Past Due
Day 15	(15 days after Due) Bill is Delinquent, Payment Penalty starts and is payable on a monthly basis, Suspension of Notice letter is sent
Day 20	(5 days after Delinquent) Termination Process starts
Day 25	(5 days after Termination Letter mailed), Earliest Termination

The A.A.R. billing schedules are inconsistent as shown in Table 3(Rev). A typical credit card timeline is added for a comparison. Mr. Ferry's goal to "avoid confusion" is not possible if the A.A.R. billing schedule requirements are followed as the minimum times between events.

Table 3 (Rev) – Comparison of Present and Proposed Billing A.A.C. Schedules for Various types of Utilities.

Type of Utility	Billing Due (Mailing Date)*	Past Due or Delinquent (days after Billing Due)	Termination (days after Past Due)
Electricity	0	+15 days	+5 days after letter
Natural Gas	0	+10 days	+5 days after letter
Water	0	+15 days	+10 days after letter
Telephone	0	+15 days	+7 days after Past
Sewage	0	10 for Past Due	+15 to Start Term. + 5 days after letter
Credit Card	Purchased up to 31 days before	+20 days	Between 21 and 51 days after purchase

* There is a technical definition of when "deemed" but when mailed is mostly accurate.

It is recommended that:

[51] This schedule concurs the Ms Diaz Cortez "Direct Testimony on Behalf of RUCO," of 28 June 2007, hereafter "**Cortez Direct Testimony**"

(1) That Past Due dates conform to the A.A.R., using 15 days after Billing date.

(2) That all proposed billing schedule changes be denied.

Q. What is your response to Mr. Ferry's Rebuttal on billing rule?

A. Mr. Ferry Rebuttal of Ms Diaz Cortez Direct Testimony stated "the bill date to reminder notice being mailed is unchanged at 25 days."

Mr. Ferry failed to respond to my Supplemental Testimony, mostly repeated above, so it is not lost as this case continues.

Q. Do you have any changes to your recommendations concerning Billing?

A. No. Each of my two recommendations remains as stated in my Supplemental Testimony

(1) Conform to the A.A.R. billing date of 15 days and thus will <u>not</u> be consistent with UNS Gas and

(2) Do not make any changes to the UNSE Rules and Regulations (R&R) on this issue.

Q. Do you have any comments about UNSE Rebuttal concerning Billing Agents?

A. Yes. My Testimony has been ignored by all UNSE Testimonies to date. It is summarized as sub-issue 2.3.

<u>Sub-Issue 2.3 - Predatory[52] Loan/Check Cashing Facilities as Billing Agents.</u>

See Exhibit B of my Direct Testimony provides the basis, discussion and recommendations to the proposed changes in billing statements. UNSE refers ratepayers to these facilities hired as UNSE billing agents to pay in person by cash "at multiple 'ACE Cash Express Stores" or an "OK Quick Cash" facilities located throughout the UNS Electric service territory."[53] It is not appropriate to use possible predatory loan/check cashing facilities as UNSE billing agents for lower income ratepayers to pay their bills in "cash" since most do not have a bank account and also will have to pay a "check-cashing" commission to "cash" their paycheck in order to pay their bill in cash.

No changes in Testimony or recommendations are necessary. Enclosure B-3 in my Supplemental Testimony provides the present UNSE Payment Agents for making cash-only bill payments. The UES website lists 12 ACE Cash Express and one QA Quick Cash

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[52] In this sub-issue, "predatory" is used for quick loan facilities that charge more than 30% per annum for loans. Most of these facilities have annual loan rates around 400% per annum. As provided in my Initial Testimony, the recommended Regulatory Agency rules permitted loan facilities to be billing agents when the annual loan interest rate is 30% or lower, recently enacted by Congress as the maximum for service personnel.

[53] Ferry Direct Testimony, page 8.

facilities.[54] Enclosure B-4 provides how one could pay their bill online with a bank withdrawal or with a credit or debit card with a third-party administration fee of $3.95 per payment.

The Recommendations in Exhibit B remain unchanged:

(1) Do not allow payday loan organizations as payment agents. [I have read in the news articles that TEP, APS and SW Gas have stopped using payday loan companies as billing agents. UES (UNSE, UNSG) has not made a known public statement. I will keep pressing for this change until verified, when UES's WebPages and billing statements are changed and these "billing agents" have been removed.]

(2) Do not require any fees for online bill payments including credit card charges.[55]

Q. Did the UNSE Rebuttal respond to your Revised Billing Statement recommendations?

A. No. My Testimony on this issue has been ignored by UNSE. It is summarized as sub-issue 2.4.

Sub-Issue 2:4 – Revised Billing Statement. See Exhibit B for detailed recommendations to changes proposed to the billing statement sent monthly to UNSE ratepayers. No changes in Testimony or recommendations from that in Exhibit B are necessary.

There were fourteen detailed recommendations to revise a new billing statement format presented in the UNS Gas Rate Case as found in Exhibit B. Since billing statements for UNSG and UNSE are similar, these same detailed recommendations apply.

Q. Did the UNSE Rebuttal respond to your Rules and Regulations document recommendations?

A. NO. My Testimony has been ignored by UNSE Testimonies to date. My testimony is summarized as sub-issue 2.5.

Sub-Issue 2.5 – R&R Publication. See Exhibit B and specific recommendations to publish the ACC-approved UNSE Rules and Recommendations (R&R). No changes to the Magruder Direct Testimony or recommendations in Exhibit B are necessary.

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[54] See www.uesaz.com/Customersvc/PaymentOptions/Agents.asp (verified 9 July 2007)

[55] See https://secure3.i-doxs.net/unisource/OneTime_Add_UniElec.asp?Ac (assessed via UNSE website, verified 9 July 2007)

Part V – ISSUE 3

Costs to Improve Electricity Reliability in the Santa Cruz Service Area[56]

5.1 Reliability Cost Issues in the Santa Cruz Service Area.

Q. Why are Reliability Issues in Santa Cruz Service Area important in this rate case?

A. As a long-term issue, expenses to rectify reliability issues impact the Company's costs and thus impact rates. As a customer, this directly impacts my bill. This cost issue is also long standing in the context of original reliability problems, ACC reviews, Settlement Agreements, ACC Orders, and compliance verification.

Q. Are you satisfied with UNSE Rebuttal and its response to this issue?

A. Absolutely Not. The two-page UNSE Rebuttal shows a lack of UNSE understanding of these issues[57] and the "cost" consequences for UNSE and/or its ratepayers. UNSE's inactions or incomplete actions are presented in some detail in my Surrebuttal Testimony.

Q. Why do you claim this UNSE response did not understand the importance of your Testimony?

A. My testimony present objective and referenced evidence that two settlement agreements and at least a half-dozen ACC Orders have not been completed or implemented, as required. All of these requirements are related to improving reliability or are the consequences of poor reliability in the Santa Cruz service area. Failing to comply/complete and not met agreements, is not acceptable corporate behavior. This must be considered in this rate case because the Company should not have a higher rate base for claiming such expenses.

Q. Are you implying that because of failure to complete agreements and Commission Orders some expenses or costs should be removed from the rate base?

A. Exactly. Some of these expenses are "soft" expenses, such as facilitating the Citizens Advisory Council and others are "hard" expenses with associated dollar objective measures.

Q. Can you expand this answer with some examples?

A. Yes. But first, let me be clear on one point.

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56 Magruder Supplemental Testimony, Part V, Issue 3, Costs to Improve Electricity Reliability in the Santa Cruz Service Area, pages 22 to 49 inclusive.

57 Rebuttal Testimony of Edmond A. Beck on Behalf of UNS Electric," of 14 August 2007, hereafter "**Beck Rebuttal**" His testimony indicates the issue in my testimony is reliability has already been "litigated." This is no true, as the Santa Cruz reliability hearings, the re-opened ACC Docket No, E-01032-99-0420 remains open and there has been no decisions made in this regard. Further, during those hearings and Case No. 111 Line Siting hearings, whenever "cost" was discussed, the Company objected and said cost was not relevant to the issue and to defer all cost issues to the next Rate Case which is now.

In my view, the electricity services provided in this service area are continuous. Some agreements and orders were made during the Citizens' era continues in full force today as UNSE obligations and are unchanged (except for the company's name and address) to UNS Electric. These reliability-related agreements and ACC Orders were not modified in any other way on 11 August 2003. Corporate "amnesia" is an unacceptable excuse for broken promises and agreements made earlier, in some cases, by the same Citizens' employees then; and are now, UNSE employees in the same positions.

Q. What is your first example of an agreement that remains incomplete?

A. As testified, the first was the City of Nogales-Citizens Settlement Agreement approved and implemented by an ACC Order as "liquidation of damages" because of poor service.[58] Parts of it have not been completed and remain open. My Supplemental Testimony provides these details and are summarized under the below headings:

a. Santa Cruz Economic Development.[59]
b. Funding Four-year Scholarships/Loans[60]
c. Create a Citizens Advisory Council[61]
d. Determine the order of circuits after Transmission Outages[62]
e. Develop a Mutually Acceptable Service Upgrade Plan[63]
f. Establish a Mutually Acceptable Franchise Agreement[64]

Q. How important was this agreement to the ratepayers and local government?

A. The City, which also was acting for customers in the County, was so displeased with electricity service it terminated its 25-year franchise agreement with Citizens and it filed a Formal Complaint to the Commission, both actions considered as evidence of their position. After a long series of negotiations including using the good offices of the ACC Staff, a settlement agreement was approved by the City Council and incorporated in an ACC Order.

Q. Why is completion of these still important?

A. First, they were mandated as compensation for poor service. Second, each was a mitigation element considered vital to permit this utility to continue operations. Third, each had defined and important benefits as compensation for poor service. Fourth, completion improved

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58 Magruder Supplemental Testimony, page 23 line 28 to page 26 line 3.
59 *Ibid.* page 24, lines 1 to 11.
60 *Ibid.* page 24, lines 12 to 18.
61 *Ibid.* page 24, line 19 to page 25 line 6.
62 *Ibid.* page 25, lines 7 to 17.
63 *Ibid.* page 25 lines 18 to 24.
64 *Ibid.* page 25 line 25 to page 3.

cooperation, public relations, service, and fulfilled needs. Data request to UNSE for details were denied.

Q. Why is cost important for the Citizens-City of Nogales agreement?

A. Most of these mandated actions were "soft" with respect to dollars except one. The annual four-year scholarship was for $3,500.[65] This "Citizens" or now "UNSE" scholarship/loan would be one of the largest in the County. It was designed specifically to have recipients return to the county and work, thus improving the community educational level. Our County, with 19.4% of the adult population with less than a ninth grade education, needs local college graduates. In fact, I demand this scholarship be implemented.

Q. What about the second agreement?

A. This is the ACC Staff-Citizens Settlement Agreement[66] that implemented a series of specific and detailed reliability improvements. A summery of some details is in the Supplemental Testimony.[67] A few are easy for a local ratepayer to track and determine completion, which include replacement of past-lifespan utility poles and replacement of known defective and improperly installed underground cables. There were specific detailed projects for pole and cable replacement, with dollars and number of poles/feet of cable to be replaced. Some was accomplished; however, I know much was not. Some of these projects over-ran their budget or required more poles or cable. These provide quantifiable compliance measures.

Q. With respect to the ACC-Staff Settlement Agreement, what was your recommendation?

A. The known and approved total cost for both poles and cable replacements is removed from the rate base. Therefore, for pole replacements $9,155,000 and for cable replacement $6.406,520 should be removed from capital expenses attributable for work accomplished by this Company in this rate case.[68]

Q. How should the removal of this $15,565,520 be done in this Rate Case?

A. I have not claimed to be an expert on how to accomplish this kind of reduction in allowed expenses; however both the ACC Staff and RUCO have the requisite skills in this area, I am sure there are procedures to remove these expenses from that claimed by the Company.

Q. Are there other issues that involve the ACC Staff-Citizens Settlement Agreement?

A. Yes. This involves the second transmission line mandated by ACC Order No. 62011, which was required to be operational on or before 31 December 2003, of a $30,000 per month

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65 *Ibid.* page 24, lines 12 to 18.
66 *Ibid.* page 26, line 4 to page 35, line 12.
67 *Ibid.* page 23, line 14 to page 35, lines 12.
68 *Ibid.* page 34, line 24 to page 35, line 13.

penalty would be assessed.[69] A TEP-Citizens Project Development Agreement (PDA) for this project was included within the Joint TEP-Citizens Application for a CEC by the Siting Committee in Case No. 111, transferred all responsibility for development, design and construction from Citizens to TEP and included other second line alternatives than that proposed to ensure a second line would be in place prior to the operational date in ACC Order No. 62011. The agreements in this PDA also have not been met. No development efforts presently exist.

These unanswered questions that impact rates are many but without a project that complies with this PDA they are not known. This PDA also specified the maximum cost for Citizens (now UNSE) with TEP absorbing the remainder. Again, another "promise", agreement, and ACC Order No. 62011 of 2 November 1999 compliance remains incomplete.

Q. You testified about this second transmission line and made some recommendations?

A. The existing proposal for a 345 kV transmission system will probably never be constructed to be the second transmission line required by ACC Order No. 62011. The existing CEC for a 345 kV system will be mute.

UNSE should be ordered to cancel its participation in that project, substitute another for the second transmission line CEC Application, and get started on a fresh approach. These alternatives were presented in my Testimonies in the re-opened ACC Docket No. E-01032C-88-0420; which resulted in ACC Order No. 62011.

Further, all future expenses pursuing the TEP 345 kV project should not disallowed in any future rate cases. Note, the 345 kV project is a TEP project and not a UNSE project.

Q. Are there any ACC Staff recommendations for expenses incurred under the ACC Staff-Citizens Agreement?

A. Not yet. When these expenses eventually do come to light, the Commission is on record in the ACC Decision No, 62011, that some expenses prior to November 1999 may not be appropriate.

The ACC Staff has not presented these inappropriate expenses during this rate case.

Q. Did the Beck Rebuttal questions your understanding of turbines and electricity operations?

A. Yes. One of these two pages concerned his ignorance about my turbines, generators, and complex, dynamic electrical system experiences in the past 40 years. I will respond to each detail of the UNSE Rebuttal.

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[69] *Ibid.* page 28, line 11 to page 29 line 24, page 35 line 14 to page 45 line 22.

Q. Is Mr. Beck off base when it comes to understanding your background and experience with electricity systems?

A. Yes. I will discuss this in terms my undergraduate, mid-grade officer, graduate, post-graduate, industry, and post-industry relevant training and educational experiences he overlooked from my resume in Exhibit A of my Direct Testimony.

My undergraduate education at the United States Navel Academy was under the "old" system. This system was a comprehensively managed educational program to cover theory, knowledge, and practical applications of that knowledge with practical hands-on experiences during summer cruises. We had courses on the thermodynamic properties of steam, mechanical systems, electric and steam turbines, total ship system design with ship electrical systems integrated into equipment operation under normal, casualty, and emergency modes of operation found in combat. We designed "gas-turbine' powered ships (all cruisers, destroyers and frigates in the US Navy today use gas-turbines). all-electric drive ships, and each with performance cost-benefits determined during each design phase. Our two-years of electrical engineering were intensive with demanding "practical works' or laboratory analytical drills. Our summer cruises where challenging and planned knowledge-to-skill experiences. The first summer, was eight-weeks of hands-one engineering training in boiler to steam, steam to steam and electrical, and electrical distribution operations and maintenance experience filling the roles of enlisted boiler technician (BT), electrician mate (EM), and machinist mate (MM). One unique course was Operations Analysis, the basis for cost-benefit analysis process used today.

After graduation my first assignment was in missile and gunnery fire control where I managed control of ship turrets, gun mounts and fire control directors. These equipments had rapid electrical demand changes on the ship's transmission system, which greatly exceed the benign demand changes on the electrical grid. Each system had both primary and electrical distribution systems that were exercised to their limits frequently. My second assign was as an ASW officer with sonar and missile mounts. Sonar systems have complex electrical demands, such as the discharge of 1 MW of power within 0.03 seconds, as a series of pulses, or required a series of special distributed generations with both capacitance and fly-wheel energy storage equipment. My later sonar experiences used more complex electrical power systems,

My mid-level education and training experiences were at the Naval Destroyer School, a six months demanding course that qualified me to be an Engineering, Weapons and Operations office with additional cruise time. I traced and made a schematic of the entire electrical generation, transmission busses, distribution transformers, for three different kinds of electrical circuits, including 60 Hertz AC, 400 Hz AC and 26 volt DC, all on the same ship. During at sea time, as a Navy Lieutenant, with my classmates, we performed EVERY function at EVERY station manned throughout the ship conducting training including extensive electrical drills.

The next tour at sea, I experienced 20 of 24 months in combat at sea 83% of the time. We only were in port to perform preventative and corrective maintenance that might have been unsafe at sea. When the enemy wants to destroy, damage or kill you and your ship, all hands were cross-trained in many additional functions. As the Officer of the Deck and Senior Watch Officer, I was the "manager" of this entire process that included the electrical system and routinely performance before the enemy or during drills, in all forms of operation. (We even were the primary recovery ship for two orbits during *Gemini XII* space mission.) Obviously, my prior hands-on-operational experiences gave me knowledge and skills necessary to control any form of excursion from the norm. This responsibility and delegated authority was similar to a utility's control room management experience.

Next, I attended the Naval Postgraduate School where I was a Physical Oceanography student for two years. 'Physics of the sea' would better explain the curriculum. Emphasis on underwater acoustics, included courses with the electrical engineering department that involved sound generation, transmission, and reception processing theory, knowledge, and hands-on-lab work, which is highly technical. The buildup for these courses included mathematical courses that exceeded the requirements for a MS in mathematics. Again, we went to sea on an oceanographic research ship making transmission loss measurements. My section of 13 officers included seven Rickover-trained submarine and surface ship nuclear-power qualified engineers. They taught me how to study and were stiff competition for "As" required to keep me on the Dean's List.

My later Navy experiences were applied planning oriented finding Soviet submarines which used all these prior skills, as understanding al the threat's and friendly submarine and surface electrical system is just one of the keys for success, as these systems provide critical signature clues. I also was on a Curriculum Review Board for the Naval Postgraduate School and my recommendation to add an additional "EMF Compatibility Course" was accepted in the ASW Technology degree program because EMF interfered with underwater signal detection. EMF compatibility is an important radiated and background noise issue. I also took several additional post-graduate level Electrical Engineering courses at the University of Rhode Island involving complex electrical beamforming and processing for advanced sonar systems, some now having up to 24 arrays, each up to five miles long being towed behind ships or other systems with high power pulses using tens of MW per pulse which extend to minutes of active sonar radiation, transmission measurements, and receiver sensitivity.

Using the GI Bill, I completed the two-year University of Southern California MS in Systems Management with an "A" in every course. This was a "systems" course that expanded my systems perspective with financial, individual and group psychology, human factors, R&D management, and other knowledge to skillfully handle any "system".

After Navy retirement, the next almost eighteen years involved many diverse systems, most included in Appendix A to my Direct Testimony. All involved electricity and electrical systems. The new generation aircraft carrier electric-drive ships will have eight or so 45,000 SHP electric-motor propellers (not screws), large 20-foot diameter electro-magnetic "fly wheel" for electro-magnetic catapults and arresting gear, with multiple turbines, double-redundant electrical transmission and distribution systems for several forms of electricity, high-power kinetic-energy weapons, planar array radar, sonar and communication systems using complex wave forms. These new aircraft carriers will not become operational until after 2018 and the last will be retired in April 2111 (reactors goes to DOE for disposal), over a century from now. From a planning experience view, I was the author of the first Integrated Master Plan (IMP) and schedule for that program, obviously a major effort, to keep events, task, personnel, equipment, development, testing, and construction integrated through processes, management, and goal accomplishments, with planned feedback, updates, for top management decision making including Congress, DoD, DoN, shipbuilding and integration industries. Integrated into the IMP was the Total Ownership Cost (TOC) program analysis that is integrated into design and risk management processes. Every system (over 6,000 onboard) is included, from design, operation, maintenance, to decommissioning. In fact, TOC has driven this ship's design so much that 1,700 less personnel will be assigned, with billions of life-time savings, maintenance processes automated to the extent that even airborne aircraft engine's acoustic signatures and almost all other equipment are monitored (in the F-35) so when the aircraft lands, if there is any equipment failure the proper part is ready, in the technician's hands with tailored fault test, install, post-installation performance test procedures in his palm pilot. There is an automated NASCAR-fuel, and ammo "pit stop", and even some cruise liner meal preparation systems.[70]

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[70] The first major electric-drive motored ships, now at 45,000 SHP per motor were the new cruise liners. Their famous meals cost less than the present Navy meal preparation costs, so for the past ten years, technology transfer programs have existed between cruise ship companies and the US Navy because TOC drives almost all new systems decision process.

Q. What does this have to do with Mr. Beck's challenge to you're background experience with electric utility use of turbines, maintenance and service life considerations, and other issues?

A. First, the turbine on every cruiser, destroyer and frigate is the LM-2500, with first gas turbines being used in the 50s. Naval turbines led to the electricity utility industry to the LM-2500.

Second, the electricity generated from any generator (steam, diesel, natural gas, solar, geothermal, and any other useful process) is the same, be it AC or DC, the same theory, knowledge, and rules are followed through generation, transmission, and distribution.

Third, ships are much more complex, work in a salty-marine environment under all weather environmental conditions, that exceed any natural environmental condition experienced by electricity utility generation systems.

Fourth, the electrical demand environment is trivial compared to the routine operational environment on naval ships. Shifting loads, splitting plants, changing generators, synchronizing phases, meeting standards, reliability measures, and other daily tasks and drills that cannot be done are routine. Utilities cannot be "dead in the water" because they hit an underwater mine, they must continue to operate. The processes to continue operations are alike; however. Almost all of the extraordinary naval electrical demands exceed the ability of a utility to meet.

Fifth, when I was given a tour of the Valencia turbines, the lead turbine technician was navy training as a gas turbine technician (GS) second-class petty officer (E-5) before his employment in Nogales. We were on the same wavelength without any misunderstandings. During this discussion, he agreed that naval turbine operation and maintenance processes were more demanding and an excellent training ground for transition into the easier electricity turbine employment.

Sixth, Mr. Beck seems to believe that the electric utility industry has unique auxiliary equipment needs. They are the same auxiliary systems, except for auxiliary equipment used with coal, which the Navy stopped using after World War I. Auxiliary feed water, fuel heating, forced air, condensation, and others are found with all steam-systems,[71] as all generation equipment needs supporting auxiliaries. They are as important as the prime movers; if they fail, the system may also fail, all depending upon how the system is setup with automated monitoring, controls, and backup subsystems. The ship must carry everything.

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[71] Terminology differences must be understood by the parties involved, then the electric generation, transmission, and distribution principles and process are the same for ships, utilities, aircraft, spacecraft, off-grid homes, and any other electrical things. The frequency, line lengths, and scale are the differences, not electricity.

Seventh, he also is concerned about adjustment of "nameplate" specifications being changed by auxiliary needs, a non-concern. Each piece of equipment has its specifications, which are integrated into a system through its flow, work, task, or schematic where outputs reflect the transformation by that element from its input values. This is basic systems engineering. The equipments "transformation" or operational process operates in an environment, be it thermal, load, frequency, or transient-loaded changes. These elements always impact output, but usually are just a percentage of the input. For example, the nameplate temperature environment for Hitachi Valencia turbines, below 10C (40F) is 20.65 MW and at it nominal 26.7C (~74F) is 18.00 MW, and at 40C (104F) is 15.40 MW,[72] or about a 25% reduction from cold to hottest environments, or +2.65 MW to –2.6 MW from nominal output as a function of temperature. My testimonies never stated that environmental impacts are not to considered but in many cases, such as the above example, these impacts are known and manageable.

Eight, I have operated various turbines, from cold start, hot re-start, off-line, synchronized turbines to grids, split loads, and other modes of turbine operation at every position in the process. Most utility personnel have limited capabilities to do these actions.

Ninth, systems engineers are cross-trained in all fields. The national, regional, utility, subsystem, to user planning, operations, maintenance, and management are not especially challenging. I have eight years of experience in line siting, utility acquisition, electric and gas rate cases, purchase power and fuel adjustment clauses, reliability assessments, and other knowledge and experiences, focused on my county and its external interfaces. None of these cases required execution of "planning" but an understanding of the planning inputs, process, and outputs, as utility planning is just another system.

Tenth, systems engineers routinely work with many diverse disciplines and employ many varied and relevant processes, including reliability engineering and system risk management processes which appear weak at UNSE. Mr. Beck has stated reliability engineering in not applicable to UNSE. However, reliability-engineering analysis directly impacts systems that is very unfortunate for UNSE. Reliability engineers primary roles are to "design out failure" or reduce it to such a low probability, failures occur so rarely, then the system meets expectations. Reliability engineering develops designs and processes to reduce the time to repair. Reliability engineering and risk management should be significant drivers for any new system design.

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72 From UNSE Response to Magruder Data Request MM DR 4.1a.

Eleventh, all naval ships interconnect with the "grid" routinely. This is not magic and is similar to any other electrical operational function. The steps are similar. During Hurricane Katrina, several naval ships were supplying electricity to cities where the utility systems failed. In San Diego, the nuclear submarines there routinely practice this function. The Navy (and other ships) is the primary backup power, if transmission is lost, to that community.

Finally, there is no requirement that my "experience involves ensuring that utility customers receive reliable energy and planning generation, transmission and distribution that affects an interstate and regional grid" as that is why I pay a utility to perform those functions. I also don't run sewage, gas distribution, filling stations, or the post office. But, understanding how these function, the systems approach, and environmental impacts[73] are experiences transferred from one discipline to another. In fact, this cross-industry experience transfer is probably one of the primary ways new technologies and innovations occur. Staying inside one's industry shell inhibits creativity and increases the probability of failure. The ESRI Intell-Grid has no new functions or features now performed by the information technology (IT) industry, as it is just another IT application; however, acceptance by the stodgy utility industry is its major environmental challenge, the IT is already there.

Q. Do you agree with the Beck Rebuttal that you "forecast" electricity demand?

A. No. The utility company that serviced the Santa Cruz service area produced all electricity demand forecasts. I did no electricity forecasting as I have always relied on the Company's data. Additional Santa Cruz load information for January through June 2007 has been received which has a new peak for this service area.

The following new Table 7 (Rev) shows the actual Peak Demand for each year since 1993 and "forecasts" from organizations that have managed the Santa Cruz service area through 30 June 2007. Each band of ten MWs is the same color, so one can see how accurate the "forecasts" to actual peak for that year. Data 2005 and 2006, based the testimony in these proceedings have not been consistent. The "notes" record the data sources of all data, which indicated only utilities information is shown in Table 7 (Rev).

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[73] In the context of systems engineering, the "environment" is the total environment that includes natural, financial, management, market, risk, operational, security, and any other outside factors that impact a system. Also a "system" is anything between an atom and the universe, with each lower level being a subsystem of the higher level. All systems operate in an environment with inputs, transformation, and outputs. Interfaces exist between the environment and the system, between inputs and transformations, and between transformations and outputs. Transformations are the work, the processes, the action, and what is done to an input that results in an output. Systems Engineering primary challenges are al all system boundaries. These boundaries are where integration and interoperability processes have significant impacts and where most system failures occur.

Two UNSE forecasts are in these proceedings, one for a 3% annual growth rate and another for a 6% annual growth rate. These UNSE "growth rate" forecasts are shown.

During the 1990 to 2000 decade, census data have the annual growth was 1.7%.[74] The latest Arizona Department of Economic Security (ADES) official population predictions show a growth rate of 2.74% in 2007, 2.47% in 2010, 1.17% in 2015, and 1.06% in 2020 and continually decreasing through 2055 at 0.71%.[75] These are official population forecasts, which show a continual decline of the growth rate in the County.

Mr. Beck must consider this sentence to be offensive: "Since 90% of the county lives in this service area, it appears the 5% [UNSE growth] forecast maybe to high and the 3% [UNSE] growth forecast is still higher than expected,"[76] This does not state that electrical growth equals population growth but that population growth appears lower than Beck Testimony's 6% and maybe lower than 3% in the future. Mr. Beck indicated that this population forecasting is not related to electricity growth but I have not forecast either, just showing two relationships. If UNSE uses a 3% and 5% growth rates for electricity, while the population grows at less than 2.0%, Mr. Beck has not provided any references or supporting information for his statement.

In summary, I never forecast electricity demand. I have used population forecasts as future growth indicators that will limit demand growth when our County is built out. The population growth will stop when water runs out, estimated at about 71,000 for Santa Cruz AMA.[77] Using the maximum population and population growth, on can determine about when this will occur. Using that year, then the UNSE forecast demand would show the maximum electricity capacity for this population-constrained service area or between 115.8 MW and 137.3 MW without considering distributed generation and renewable energy reductions. Thus my forecasts are conservative, factual-based with sources for all provided in my Supplemental Testimony.

Mr. Beck appears shooting from the hip without supporting data. One data request (sent 3 times) for his working papers finally was responded to with there were none. All other UNSE Direct Testimonies had extensive sets of working papers. He has none.

Q. Why is the long-term peak demands for this area important?

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74 Magruder Testimony in ACC Docket No. E-01032A-00-0401, pages 181 to 184 for additional Santa Cruz service area growth details.

75 "Santa Cruz County Population Projections 2005-2055, ADES, Research Administration, Population Statistics Unit, approved by ADES Director on 31 March 2006, found on County and ADES websites.

76 Magruder Supplemental Testimony, page 39, lines 1 to 4.

77 *2004 Santa Cruz County Comprehensive Plan*, revised 2005, page 65.

A. Table 8 in my Supplemental Testimony clearly shows that using one of the four available turbines for peaker power is much less expensive than installing another LM-2500 for approximately $14 million in the near future. This Table, as discussed, is VERY conservative, and easily could be too high by a factor of three. Also, UNSE is now purchasing additional power on the WAPA lines to ameliorate that 65.8 MW restriction.

I have been recommending for years a new substation is required in Nogales The one in the City of Nogales is poorly located for many reasons. A location outside the 100-year floodplain is essential. Based on my many conversations with the County Flood Manager, he would demand 500-year floodplain since this one-substation is a critical facility. When this new substation issue is resolved, then additional generation there and upgrades help split the load, provide local backup, and increase local generation to reduce reactive power needs.

Q. What are the present reliability issues that are of concern?

A. All substations need upgrades recommended in the Powers Engineering Report, and distribution lines and poles replaced. Distribution reliability is the primary cause of lost power, and not the transmission line shown in Table 11. UNSE does not maintain substation reliability information as required NERC/WECC Reliability Criteria. Using IEEE Std 1366 data, see Table 12 of my Supplemental Testimony[78] to standardize collection and analysis.

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[78] Magruder Supplemental Testimony, page 47, Table 12. Definitions of Key Distribution Reliability Indices" for ASAI, CAIFI, MAIFI, SAIDI, and SAIFI as a minimum.

Table 7 (Rev). Actual and Forecast Annual Peak Demand for the Santa Cruz Area. The actual observed values, in the second column, show the actual annual peak demand in MW, with forecasts that are "higher" than forecast in **red** and "lower" than forecast in **blue**. Each 10 MWhr is shaded in a different background color. Newer forecasts are to the left and older to the left. Above the line between 2007 and 2008 indicates "history" which future demand predictions are below. All data shown are directly from many different Company references discussed below this table.

REAL WORLD Data		FORECAST PEAK DEMAND for the Santa Cruz Service Area												
Year	ACTUAL Peak Demand	UNSE Rate Case (3% gr)	UNSE Rate Case (5% gr)	UNS Electric and SEC	Very Slow Scenario	TEP/ UNS Electric	UNS Electric	TEP Hot Forecast	TEP High Forecast	TEP Normal-ized	RAC 2 Hot	RAC 2 Normal	Citizens C/B Analysis	Citizens Briefing
		Mar 2007	Mar 2007	Dec 2006	Oct 2005	July 2005	June 2004	Feb/Apr 2004	Feb/Apr 2004	Feb 2004	2000	2000	1999	1998?
1993	40.0													
1994	43.7													
1995	41.6													
1996	41.9													
1997	42.5													
1998	45.3													
1999	50.36												46.7	50.5
2000	52.60											50.2A	48.0	52.6
2001	50.54										60.0	55.0	49.9	55.7
2002	57.99										62.0	58.0	51.6	56.9
2003	57.64							59.1		57.5	65.0	60.0	52.4	58.2
2004	60.768						61.4	61.4	64.4	59.7	67.0	62.0	54.5	59.5
2005*	69.408 or 69.6			69.5			63.6	63.2	63.6	66.8	61.9	69.0	64.0	60.7
2006*	71.7 or 73.152			71.1	72.7		65.3	64.9	65.8	69.0	64.0	72.0	66.0	
2007	75.6			74.0	74.1	63.6	66.7	66.5	67.9	71.3	66.1	74.0	68.0	
2008		76.1	76.1	76.5	76.5	65.3	68.1	68.0	70.1	73.5	68.2	76.0	70.5	
2009		78.4	79.9	79.1	77.0	66.7	69.4	69.5	72.2	75.8	70.3	78.0	73.0	
2010		80.7	83.9	81.7	78.5	68.1	70.8	71.0	74.5	78.2	72.5	80.0	74.0	
2011		83.2	88.1	84.3	79.9	69.4	72.2	72.5	76.8	80.6	74.7			
2012		85.7	92.5	86.9	81.5	70.8	73.6	74.0	79.2	83.1	77.0			
2013		88.2	97.1	90		72.2	74.9	75.4	81.6	85.7	79.4			
2014		90.9	102.0	92		73.6	76.1	76.7	84.1	88.3	81.8			
2015		93.6	107.1	95		74.9	77.3	78.8	86.7	91.0	84.3			
2016		96.4	112.4	98		76.1	78.5	79.3						
2017		99.3	118.1	101		77.3	79.7	80.6						
2018		102.3	124.0	103		78.5	80.9	81.9						
2019				105		79.7	82.0	83.3						
2020				107		80.9	83.3	84.6						

Historical Peak Demand Data

Historical Forecast Peak Demand Data

Actual Peak Demand Data

Forecast Peak Demand Data

Table 7 (Rev). Actual and Forecast Annual Peak Demand for the Santa Cruz Area. The actual observed values, in the second column, show the actual annual peak demand in MW, with forecasts that are "higher" than forecast in red and "lower" than forecast in **blue**. Each 10 MWhr is shaded in a different background color. Newer forecasts are to the left and older to the left. Above the line between 2007 and 2008 indicates "history" which future demand predictions are below. All data shown are directly from many different Company references discussed below this table.

REAL WORLD Data		FORECAST PEAK DEMAND for the Santa Cruz Service Area												
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		Mar 2007	Mar 2007	Dec 2006	Oct 2005	July 2005	June 2004	Feb/Apr 2004	Feb/Apr 2004	Feb 2004	2000	2000	1999	1998?
2021				109		82.0		86.3						
2022						83.3		88.0						
2023								89.8						
2024								91.6						
2025								93.4						
2026								95.3						
2027								97.2						
2028								99.1						
2029								101.1						
2030								103.1						
2031								105.2						
2032								107.3						
2033								109.4						
2034								111.6						
2035								113.9						
2036								116.1						
2037								118.5						
2038								120.8						
2039								123.2						
2040								125.7						

Historical Peak Demand Data

Forecast Peak Demand Data

Forecast Data Sources and notes (reading from left to right columns)

***Actual Peak Demand (1993 to 2006)** – In the UNSE Rate Case, ACC Docket E-04204A-06-0783, the actual peak though 30 June 2007 was 75.6 MW (from UNSE Response to Magruder Data Request 4.1) measured at the Nogales Tap, which might be exceeded later in 2007. The actual peak loads for 2006 and 2005 were given as 71.7 MW and 69.6MW, in UNSE response to ACC Staff Data Request STF 1.1. In USNE response to MM DR 1.15 the peak load for 2006 was provided by UNSE to be 73.152 MW was provided as the 2006 peak load. In this UNSE response to MM DR 1.15, the peak load demands for 2003 through 2006 were provided which included a 2003 peak at 54.144 MW that occurred after 11 Aug 2003, under UNSE, while the actual 2003 peak occurred under Citizens at 57.64 MW earlier that summer. Additional peak data were in TEP's response to MM Data Request 221.c in ACC Docket E-01032A-99-0401.

UNSE Rate Case (3% gr, 5% gr((Mar 2007) – In UNSE's response to MM Data Request 1.15 (Excel spread sheet) in ACC Docket E-04204A-06-0783 for years 2008 through 2018 using a 3% and 5% growth rates.

UNS Electric and SEC (Dec. 2006) – For 2005 to 2012, from Testimony of Ed Beck in UNS Electric Rate case ACC Docket E-04204A-06-0783 and from 2013 to 2021 from the UniSource SEC Form 25 submitted in Dec 2006 and Exhibit MJD-1 to Michael DeConcini in the above UNS Electric Rate case. The SEC filing also included the earlier years, rounded off to an even MWhr as Weather Normalized Peak Demand Forecast.

UNSE "Very Slow" Scenario (Oct 2005) – From UNSE Annual Peak Load Forecast, emails in March 2006, from MM Data Request 1.9.g in ACC Docket E-04204A-06-0783.

TEP/UNS (July 2005) – From Beck Testimony of 8 July 2005, Exhibit 3 (Annual Peak Load Forecast for Santa Cruz County)

UNS Electric (June 2004) – From UES "Long-term Transmission Plans for Santa Cruz County UNS Electric System," June 2004. For years 2021 and later, the forecast is extrapolated based on a 2% growth factor.

TEP Hot, High, and Normalized Forecast (Feb/April 2004) – From Exhibit 4 (February 2004) where TEP forecast is for the average year (also in the RMR report for 2005, 2008, 2012) and the "high" for years that are hotter than normal.[79] This also has been published as "Nogales Retail Peak Forecast – April 2004:" with the years 2004 to 2020 designated as the "UniSource Forecast (MW)" and the years 2021 to 2040 as "Extrapolated Forecast (2% growth factor (MW)

UniSource Energy Services – Loads & Resources Peak (weather normalized) Demand Forecast (used by UniSource for the competition for a new Purchase Power Agreement for Santa Cruz County (February 2004)

RAC2 Hot, Normal (2000), Testimony of Rasel Craven, Citizens Director of Engineer, May 1, 2001, Docket No. L-00000C/F-01-0111, Line Siting Case No. 111, as Exhibit RAC-2, which indicated on June 30, 2000, a record of 50.2 MW was reached (marked by A) above. Values for 2001 to 2003 are from testimony, from 2004 to 2010 from Exhibit 4 (February 2004) as footnoted above. The "normal" and "hot" were for years which were average or higher than average. The R.W. BECK & Co. determined the RAC-2 forecasts in early 2000.

Citizens' Cost-Benefit Analyses (1999) of Transmission-Line Alternatives, ACC Docket E-01032A-98-0611 in Exhibit F of July 13, 1999 at Nogales Tap for "normal weather."

Citizens Briefing (1988) given to the Joint Santa Cruz County/City of Nogales Energy Commission in February 2001; however, content appeared to be dated about 1988.

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[79] See Exhibit 4 from the TEP and UES "Response to Commission Questions and Updated Response Plan for Santa Cruz County" of 9 February 2004, in ACC Docket No. E-01032A-99-0401.

5.2 Recommendations.

There are seven important recommendations to be considered that were without comment in the UNSE Rebuttal Testimony. They remain valid recommendations.

1. Decrease the rate base by $15,561,520 for failure to comply with an ACC Order No. 62011 (see above) and ensure compliance with all actions in the ACC Staff-Citizens Settlement Agreement and
2. Complete and continue to take ALL actions required by the City of Nogales-Citizens Settlement Agreement.
3. Ensure that the UNSE does not receive expenses for actions incurred prior to the acquisition, such as the $122,842.89 for utility pole replacements and $159,597.51 for underground cable replacements presented above because they were Citizens charges.
4. Obtain more access on the WAPA lines, with its considerably lower wheeling costs, than using TEP facilities (rejected by Citizens in its trade-study for the ACC).
5. Be consistent with objective data for load capacities when presenting operational data.
6. Compute reliability indices at the substation level, as required by NERC/WECC reliability criteria.
7. Delete considerations of a 345 kV line and get started with a second parallel transmission line for each substation, either 115/138 double-circuit or a backup 46/59 kW double-circuit.

AND to cease "fear mongering" by saying the "lights are going out" in Nogales in 2002, 2003, 2004, 2005, 2006, 2007, 2008, 2009, 2010, 2011, 2012, and later until firm clear alternatives have been objectively considered.

Part VI – ISSUE 4

CARES and CARES-M Tariffs

Q. Have your concerns about CARES and CARES-M in your Direct Testimonies been answered by the Company?

6.1 Response to UNSE Rebuttal Testimony.

A. No. The Company has not responded to the CARES and CARES-M testimony in Part VI of my Supplemental Direct Testimony.[80] The specific CARES recommendations are in section 6.4 and the CARES-M recommendations are in section 6.5 of my Supplemental Direct Testimony.[81] The four CARES recommendations aim was to improve participation[82] and the CARES program itself. The aim of the seven CARES-M recommendations was to support those on life support equipment during an electrical outage.

Q. Why do you feel your recommendations are important?

A. The CARES-M concern possible life-of-death for customers on life-support equipment.

The Company has a mission to ensure electricity reliability and safety, which applies to this concern. Taking action such safety concerns before the loss of life is responsible corporate behavior.

During earlier Commission UNS Electricity reliability hearings, then ACC Chairman Gleason questions clearly demonstrate his concerns about this kind of life-support recommendations, which pertain to both CARES-M participants and all other UNS Electricity customers on life-support equipment. My Issue Number 4 is intended to provide a comprehensive response to his penetrating questions.

Without the utility's support and an established working relationship with local officials for emergency support,[83] actual life-support-equipment operational checkups can not be planned in advance (such as each area having a list of such persons, their specific medical support equipment needs for electricity such as the duration of installed backup battery support, then these notifications can not take place.

The CARES recommendations support the ACC Staff's recommendations. I concur and support all eleven of the ACC Staff's recommendations as discussed below.

Q. Can you respond to the Company's Rebuttals concerning these two programs?

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80 Magruder Supplemental Testimony, 51 to 54.
81 *Ibid.* see pages 53 and 54 for these seven recommendations.
82 *Ibid.* see Table 13, page 52 which shows that the number of CARES potentially eligible participants that are not participating in CARES are approximately 9,876 in Mohave County and 3,349 in Santa Cruz County.
83 *Ibid.* see page, over 13,000 families who are lower income are not in the CARES program.

A. Yes. I will respond to Mr. Ferry's Direct and Rebuttal Testimonies[84] first.

Mr. Ferry responded only to the excellent testimony of the ACC Staff witness Ms. McNeely-Kirwan[85]; however, Mr. Ferry did not respond to <u>each</u> of the Staff Recommendations on pages 14 and 15, other than recommendations 1 and, in general to her recommendation 4, without commenting on the $400 per year per household for Warm Spirits emergency bill paying program. Her other recommendations (2, 3, 5 to 11) <u>require</u> answers by the Company in testimony so they can be considered for inclusion in the eventual ROO that will be issued by the Administrative Law Judge (ALJ). Without such comments, should acceptance be assumed for these other Staff Recommendation?

Q. Where there other responses in the Company's Rebuttals concerning these programs?

A. Yes. Mr. Erdwurm's Rebuttal[86] provided testimony that the CARES-M rate discount would be increased from $8.00 per month to $10.00 month and that these would remain as separate tariffs. The Company's recommended CARES rate discount remains at $8.00.

Q. Are you satisfied with the Company's responses concerning CARES and CARES-M?

A. Mr. Erdwurm's response is positive; however the shallow, incomplete response by Mr. Ferry is non-responsive to Ms. McNeely-Kirwan and irresponsible with respect to my concerns and recommendations.

Q. How do you recommend such non-responses to these CARES and CARES-M recommendations by the ACC Staff and yourself be handled?

A. I feel any recommendation[87] in a witness's testimony needs a response by the applicant; unless, by default, such recommendations are acceptable by the Company without modification or additional discussion. No response to a proposed recommendation, in my opinion, means complete Company acceptance as recommended by a witness and thus automatically will be considered by the ALJ for inclusion in the ROO for this Rate Case, without further discussion.

Q. Does the complete your Surrebuttal on this issue?

A. Yes, but there remain unanswered questions:[88]

1. What are UNSE's concerns for those with electrical life-support equipment that are NOT CARES-M customers?
2. Does UNSE have any moral, ethical, and safety responses for these people whose lives are dependent on reliable electricity?

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84 "Direct Testimony of Thomas J. Ferry,

85 "Direct Testimony of Julie McNeely-Kirwan Utilities Division" of 28 July 2007, hereafter "**McNeely-Kirwan Testimony**".

86 Erdwrum Rebuttal, pages 16 and 16.

87 In all of my testimonies in this case, for my recommendations, I underline <u>recommendation</u> for emphasis.

88 Magruder Supplemental Testimony, page 51.

Part VII – ISSUE 5

Environmental Portfolio Standard (EPS) and Renewable Energy Standard and Tariff (REST) Surcharges

Q. Have your concerns about meeting the EPS goals and REST Surcharges in your Direct Testimonies been answered by the Company?

A. No. Finally, the Company provided information about these two programs in these proceedings with the Rebuttal Testimony submitted by Mr. Hansen on this important topic.[89] The Commission is in transition from its Environmental Portfolio Standard (EPS) to the Renewable Energy Standard and Tariff (REST) programs with different rules for each.

Q. Do you have any responses to Mr. Hansen's Rebuttal?

A. Yes. Let me go through his rebuttal, which has four issues, before reviewing recommendations for these programs.

7.1 Response to UNSE Rebuttal Testimony.

Q. What is your response to his first issue[90] involving failing to meet EPS goals?

A. His first issue discussed meeting the existing EPS annual renewable energy goals. He stated that UNS Electric met only 40.68% of its annual renewable energy requirement during the test year that was 1.025%[91] or stated another way, only 0.417% renewable energy (including "multipliers") was used by UNSE during the Test Year. He also testified that no other Arizona utility has met the renewable energy requirements since EPS implementation. He stated that no utilities have met the EPS annual solar energy requirements. He cites inadequate funding as the reason for this failure. This is most unfortunate as the Commission and public in Arizona expect goals set by the Commission to be achieved. It is most encouraging reading Mr. Pignatelli's Rebuttal where he states <u>UNSE will "comply" with the REST rules</u>,[92] which a reasonable person should assume means that UNSE will comply with all of the REST requirements summarized in Table 15 of my Supplemental Testimony.[93]

My Supplemental Testimony was also discussed EPS and solar energy goals in Table 14. Unfortunately, the statements concerning 0.00646% of total sales in 2006 concerns actual solar electricity produced by UNS Electric ratepayers. This table was deliberately computed to

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89 "Rebuttal Testimony by Thomas N. Hansen on behalf of UNS Electric", 14 August 2007, hereafter "**Hansen Rebuttal**".
90 *Ibid*: page 2 at 22 to page 3 at 2.
91 The EPS requirement is for renewable energy 1.0% of retail sales for 2005 and 1.05% for 2006, thus using 1.025% for the test year that spans these two is appropriate.
92 Pignatelli Rebuttal, page 16, lines 3 to 5. [underlining added for emphasis]
93 Magruder Supplemental Testimony, Table 15, "Some of the REST requirements for UNSE," page 58.

not take into account various "multiplier" credits, as its objective was to focus on the actual solar energy being or will be generated in the service area. Table 14 has been revised and is presented below with column titles and data corrected to reflect this intention. Considering this revision, Mr. Hansen objections for this issue are resolved.

Table 14 (Rev). EPS and Solar Energy Goals and Solar Energy Generated to Date. *Since 1997, a total of 256 MWh of the total UNSE retail load was solar generated. In 2006, the best year to date, 0.00646% of the total UNSE load requirements was from solar generated electricity in the UNSE service area, well below the EPS requirement for 10,151.4 MWh, and was 10,040.8 MWh short.*[94]

Year	UNSE/ Citizens Total Retail sales (MWh)	EPS Percent Renewable Electricity	Needed to meet EPS Standard (MWh)	Solar Generated (MWh)	Actual Percent Solar-only Generated	Annual Solar Goal (MWh)	Deficit to Meet Solar Goal
Column	(1)	(2)	(3)=(1)x(2)	(4)	(5) = (4)/(1)x100	(6) = 0.6x (4)	(7)=(6)-(4)
>2001	NA	NA	NA	57.0	unknown	NA	NA
2001	1,275,036	0.2 %	2,550	19.0	0.00149 %	1,530.0	-1,511.0
2002	1,136,581	0.4 %	4,546	19.4	0.00171%	2,727.6	-2,708.2
2003	1,392,466	0.6 %	8,355	13.3	0.00096%	5,013.0	-4,999.7
2004	1,462,633	0.8 %	11,701	10.0	0.00068%	7,020.6	-7,010.6
2005	1,631,947	1.0 %	15,210	26.7	0.00164%	9,126.0	-9,099.3
Test year[95] (2005-2006)	1,579,512	1.025%	16,168	54.6[96]	0.00345%	9,700.8	-9,646.2
2006	**1,711,420**	**1.05%**	**16,919**	**110.6**	**0.00646%**	**10,151.4**	**-10,040.8**
Cumulative Total to 2007	8,610,083	NA	59,281	256.0	0.004318%	35,568.9	-35,369.6
2007e	1,659,763	1.10%	18,257	TBD	TBD	10,954	
2008e	1,709,555	1.10%	18,805	TBD	TBD	11,283	
2009e	1,760,842	1.10%	19,369	TBD	TBD	11,621	
2010e	1,813,667	1.10%	19,950	TBD	TBD	11,970	
2011e	1,868,077	1.10%	20,549	TBD	TBD	12,329	
2012e	1,924,120	1.10%	21,165	TBD	TBD	12,699	

Q. What is your response to the second issue[97] involving UNS Electric EPS Management?

A. Mr. Hansen stated that the Magruder Supplemental Testimony indicated that (1) UNS Electric did not have the attention of UNS Electric management; (2) the EPS program is not ISO 14400 certified, and (3) UNSE lacks commitment to development of renewable energy.

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94 Table 14 used the UNSE response to ACC Staff data request 13.40, which included UNSE "Test Year Annual Report on Environmental Portfolio Standard Programs," (hereafter "ESP Test Year Report") dated June 2007 and the UNSE response to ACC Staff data request 3.137, "Deferred Environmental Portfolio Surcharge Revenue Activity", Aug 2003 through Dec. 2006

95 The Test Year values used the 2005 (second half) and 2006 (first half) from the EPS Test Year Report, page 2.

96 EPS Test Year Report, page 5. Note, multiplier credits of 2.0 for 2005 and 2006 were not included in the analysis in original and revised Table 14.

97 Hansen Rebuttal, page 3, lines 4 to 12.

First, as stated in the Magruder Supplemental Testimony, during the Test Year, UNSE had non-renewable energy expenses, including payroll, were as follows[98]:

Payroll	$27,880
Marketing	$902
Materials and Supplies	$167
Training and Travel	$1,458
Outside services & contracting	$2,923
Subtotal Test Year Expenses	$33,330

A review of these EPS program expenses, shows less than one manager-year was probably involved in this program of the $33,000 for these expenses in the Test Year. Further, a payroll total of only $40,499[99] for the <u>life of the program</u> since 2001 supports low personnel involvement including management.

Second, it appears Mr. Hansen does not understand ISO 14400. This is a corporate <u>process</u> standard used for Environmental Management. Companies, such as Public Service Company of New Mexico (PNM), have been ISO 14400-certified for years. PNM website shows how that company considers the environment at all management levels as its annual reports shows. Such environmental awareness creates a workplace process that continually works to sustain and improve the total environment. ISO 14400 is not a standard for any single program, such as EPS, but is an important environmental step to establish and maintain effective management processes.

No UniSource entities are ISO 9000-certified. This indicates the Company processes have not been third-party reviewed for quality, completeness, accountability, and compliance by its employees, a routine for the tens of thousands of worldwide ISO 9000-certified companies. During my tenure as a MBA instructor in "Operations Management" at the University of Phoenix, ISO 9000 and ISO 14400 were two <u>basic</u> building blocks used by successful companies. I have been through initial certification at Hughes where we "thought" we were doing quality work; however, to achieve ISO 9000 certification[100] allowed us to benefit from internal process reviews to improve and self-sustain even higher levels of performance. I also have been in one of the first SEI Level 5 certified organizations,[101] and at the time, the

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[98] *Ibid.* Table 1, "Summary of EPS Programs Period from July 1, 2005 through June 30, 2006," page 3. The hardware buy down program, landfill gas credits are related to material or power purchase programs and can be found in the above.

[99] *Ibid.*

[100] For several years, "management" used the expense for our 2,000 organization of $50,000 as "what is the payback". After we got there and hoisted a large "ISO 9000 Certified" banner, all managers agreed the benefits outweighed the expense (to pay and setup the third-party certification team).

[101] The Carnegie-Mellon Software Engineering Institute "maturity" level process is very demanding and specialized for organizations involved with software development, including systems engineering, testing, quality, and other parts of the company. Maturity Level 5 is the highest and when we were certified, there ware less than five such organizations. It took us over 18-months of hard work to achieve this level upgrade

largest Level 5 certified entity in the United States. I realize Mr. Hansen has never experienced an ISO 9000 or 14400 certified organization.

Third, as shown in Table 14, the failure to reach a goal for six consecutive years has not excited this company. The EPS Test Year Report has no "fix it" approaches mentioned. Comparison with TEP, which has the same program management and performance level, adds nothing for failing to continually not meet objective goals. The original UNS Electricity "Green Watts™ SunShare Hardware Buydown Program"[102] was very weak. I made written and public comments before the Commission when it was initially approved trying to make the program stronger. It failed as I warned because it was so ineptly weak it could not generate the "critical mass" in either Mohave or Santa Cruz County to really get started. The annual decrease of renewable energy rebates, complex contractual requirements including recording the UNSE contract on one's property deed, unnecessary battery storage prohibitations, and other restrictive procedural steps that were designed to quickly discourage individuals who wanted solar-electric systems. For me personally, this was true, and why I lost interest.

The new program, approved by the ACC on 21 December 2006, is more customer-friendly, has steady rebates, permits batteries, with a less restrictive UNSE contract and other features to help encourage customers to participate. It is easy to see why UNSE has a higher rate of participation in Sun Share than TEP, UNSE started near zero.

Q. What is your response to the third issue[103] involving calculations in Table 14?

A. Mr. Hansen stated that the Magruder Supplemental Testimony contained errors in Table 14. As testified above for the first issue, this table was designed to show both EPS/REST and solar generated goals and accomplishments. This is now shown in the revised Table 14.

Mr. Hansen stated a capacity conversion was improperly made; however, no such conversions[104] were made as all the values in columns 1, 2, 3, and 4 were copied directly from the UNS Electric Test Year EPS Report. His comment might be that the original column 4 was erroneously labeled in units of MW (capacity) when MWh was the intended unit of measurement. This is also corrected in the revised Table 14. This issue was due to a confused and mixed presentation that I intended to be straightforward.

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from Level 3, it considered as highly professional. What this does is establish internal self-sustaining management that impacts every decision, risk, and builds initiatives where none thought were possible. This maturity level certification process has been expanded to Systems Engineering, Quality, Testing and other disciplines in technical engineering companies.

[102] See ACC Decision No, 67178, "In the Matter of UNS Electric, Inc., - Filing to Introduce GreenWatts Pricing Plan, GreenWatts SunShare Hardware Buydown Program, and Non-Firm Purchase from Renewable Energy Resources," of 10 August 2004, hereafter **ACC Decision No. 67178**.

[103] Hansen Rebuttal, page 3, line 14 to page 5 line 15.

[104] *Ibid.* page 3, lines 21 to 23 and page 4 line 10.5.

Q. What is your response to the fourth issue[105] involving energy and capacity?

A. Various points are mentioned. He stated "energy" and "capacity" were confused; however, only energy is discussed in section 7.1, after correcting the units in column 4 of Table 14. On page 17, line 1, adding the word "system" after "solar electric energy" would have been clearer. The "52" panels was found on page 6 of the UNSE Test Year EPS Report, which combined the 24 panels at Lake Havasu City and 27 panel at Kingman, which total 51 panels which is one panel more, much less of an error than "flat wrong."

There is no discussion in the USNE Test Year EPS Report about "320 solar modules installed... capable of generating over 8,000 watts of power"[106] which is why they were not discussed in this testimony. The test year comment in the Magruder Supplemental Testimony about "no solar electricity has been generated in Santa Cruz service area"[107] is based on Table 3[108] of the UNSE Test Year EPS Report which shows no entries under "NO" which is assumed to be Nogales, as the other two abbreviations, KG for Kingman and LH for Lake Havasu City are supported by other discussions in this report.

Q. Have you responded to all of Mr. Hansen's issues?

A. Yes for the four issues, now for my response to his concerns about my three Recommendations.

First, the term "GreenWatts™ SunShare Hardware Buydown Program"[109] or "SunShare" should have been used in the first recommendation in my testimony revised below.

Second, the schedule for REST filing proposed differs from that required by the ACC. It wasn't until 9 August 2007 that an email from Mr. Ray Williamson, ACC Staff, outlined the REST submission process,[110] obviously received after submission of the Magruder Supplemental Testimony.

Q. Do you have any changes in your recommendations found in section 7.4 of your filing?

A. Yes. The Supplemental Direct Testimony recommendations in 7.4, should be replaced with the following four recommendations:

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105 *Ibid*. page 4, line 17 to page 5 line 4.
106 UNSE Test Year EPS Report, page 6.
107 Magruder Supplemental Testimony, page 57, lines 13 and 14.
108 UNSE Test Year EPS Report, Table 3, "EPS Solar Energy Production Period from July 1, 2005 through June 30, 2006, page 5.
109 This program name is in the title of ACC Decision No. 67178. On page 3 in lines 2 and 3, the term "GreenWatts™ SunShare Hardware Buydown Program ('SunShare')" is used. Regret confusion.
110 This email stated that all REST tariffs should be filed by 14 October 2007 with the Commission. The Commission expects that the UNSE and TEP REST Implementation Plans be filed in September.

(1) That UNSE continue to invigorate its "SunShare" program, as upgraded on 21 December 2006 and as expanded in its REST Implementation Plan expected filing during September 2007.

(2) That UNSE present in its REST Implementation Plan[111] details on how it will transition from EPS to REST, as required by the ACC Decision No. 69127 and rules in Appendix A of this Decision to comply with or exceed[112] all REST requirements, summarized in Table 15 or as presented by UNSE to the Commission in its REST Implementation Plan.

(3) That UNSE present its REST Tariff not later than 14 October 2007 and implemented as required by the resultant Commission Order or Decision.

(4) That all future ACC REST Reports be routed through and signed by Mr. Hansen, whose job title reflects this area, before submission to the ACC and Docket Control.

Q. Have you answered all the UNS Electric Rebuttal comments?

A. Yes. In am particularly pleased that the UniSource CEO and UNSE President Mr. Pignatelli has use the term "**compliance**" with respect to the new REST rules. Compliance does not mean only 46% as used by Mr. Hansen, but 100% compliance. The forthcoming UNSE Plan will have to show how UNSE will meet ALL REST goals and requirements.

Q. Have you finished your Surrebuttal Testimony on this issue?

A, Yes.

Q. Have you finished your Surrebuttal Testimony?

A, Yes,, this completes my Surrebuttal Testimony.

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[111] Pignatelli Rebuttal, page 16, lines 3 to 5, used the term REST "**Compliance**" Plan, which is assumed to be the same as the term REST Implementation Plan used by Mr. Hansen.

[112] It is very interesting to note that EPRI, the electric utility research institute, which UniSource and UNSE have memberships, states in its Executive Summary, "Electricity Technology in a Carbon-Constrained Future" of 15 February 2007, recommends "reasonable but aggressive deployment programs in seven specific areas...2. Increased deployment of cost-effective large-scale renewable energy resources, sufficient to exceed future State renewable portfolio requirements...." found at the ESRI website. At present I have no reproduction capabilities and may enter this ESRI document as an Exhibit during forthcoming hearings.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Kristin K. Mayes
Gary Pierce

EXHIBIT
tabbies
M. 25
Admitted

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR APPROVAL OF THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC.

Docket No. E-04204A-06-0783
Notice and Filing of the
Summary Testimony
of
Marshall Magruder
10 September 2007

As provided by the Procedural Orders of 1 February 2007, 27 March 2007, and 25 June 2007, herein is the Summary Testimony of Marshall Magruder, a Santa Cruz County UNS Electric, Inc. ratepayer.

I certify this filing has been mailed to all known and interested parties in the Service List.

Respectfully submitted on this 10th day of Septmber 2007

MARSHALL MAGRUDER

By/ Marshall Magruder

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Service List

Original and 17 copies of the foregoing are filed this date with:

Docket Control (13 copies, hand delivered)
one copy for each Commissioner and
one copy for each Commissioner's Aide)
Arizona Corporation Commission
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Phoenix, Arizona 85007-2927

Tenna Wolfe, Administrative Law Judge (1 copy, hand delivered)
Ernest G. Johnson, Director Utilities Division (1 copy)
Christopher Kempley, Chief Counsel (1 copy)
Maureen Scott, Senior Staff Counsel (1 copy, hand delivered)

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Bob Damon, Supervisor
John Maynard, Supervisor
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City of Nogales
Jan Smith-Florez, City Attorney
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Nogales City Hall
777 North Grand Avenue
Nogales, Arizona 85621-22621

Summary of Testimony of Marshall Magruder

Marshall Magruder has filed a Motion to Intervene, Direct Testimony, Supplemental Direct Testimony, and Surrebuttal Testimony in this case. Five issues were specifically detailed in these filings that analyzed the proposal with conclusions and specific recommendations.

Issue 1. Demand Side Management Programs. Company proposed seven DSM programs.
(1) Training and Education, 18 recommendations including a larger integrated program budget;
(2) Direct Line Control, 9 recommendations, some concern customer safety and new meters;
(3) Low-Income Weatherization, 3 recommendations;
(4) Residential New Construction, 4 recommendations, reduced budget $21,934;
(5) Residential HVAC Retrofit, 4 recommendations, added $20,000 for 17/18 SEER units;
(6) Shade Tree, deleted program with $65,000 savings; and
(7) Commercial Facilities Efficiency, 5 recommendations including increased rebate budget.
The reduced first-year DSM Adjustor Surcharge is $0.00058236/k for $937,428 expenses. A full-year 2008 DSM Adjustor Surcharge would be $0.00213188/kWh with a $3,424,512 budget.

Issue 2. Administrative Issues:
(1) Billing Schedule, 2 recommendations including conforming to the A.A.R.;
(2) Predatory loan/check cashing facilities as UNSE Billing agents, 2 recommendations for company, recommend the Commission adopt the National Consumer Law Center policies;
(3) Revised Billing Statement, 14 recommendations involving format and content; and
(4) Rules & Regulations Publication, 3 recommendations, use "plain English", provide copies.

Issue 3. Costs to Improve Electricity Reliability in Santa Cruz service area. Due to incomplete a City of Nogales-Citizens Settlement Agreement, an ACC Staff-Citizens Settlement Agreement, and a Program Development Agreement in the CEC Application, all implemented by ACC Orders, 7 recommendations include reducing rate base by $15,561,520 by not completing 20 utility-pole and 12 underground-cable replacement projects, provide the annual four-year $3,500 loan/scholarship, re-start the Citizens Advisory Council, work with service communities on rate design, public relations, outage plans, DSM, and others.

Issue 4. CARES/CARES-M Tariffs, 7 recommendations for improvement including adding non-CARES ratepayers who require life support equipment into mandatory first responder notification during any power outage.

Issue 5. EPS and REST Surcharges, 4 recommendations to ensure 100% compliance with REST, all 4 seemingly accepted.

The Company has not responded to most of the over 80 specific recommendations. Several DSM recommendations were accepted.

Some other issues, the TOU "demand" sampling of highest 15 minutes per Peak/Off-Peak period to determine TOU bills, identify the PPFAC Adjustor Surcharge components, new PPA impacts, prudency of present DSM program, reliability of one Nogales substation in the 100-year floodplain, customer "smart" meters, possible double A&G, and have one Santa Cruz-Mohave residential and one small business tariff to eliminate significant county rate differences.

EXHIBIT
M-27
Admitted

Marshall -

FACTS:

Unisource power distribution in the San Rafael Valley = 7 large ranches and 4 smaller ranches, 2 vineyards and multiple home sites to include the Patagonia Mts. and a new Arizona State Park near the border and just east of Lochiel Also, the community (unknown # of customers) of Santa Cruz, Sonora, Mexico. This does not include other homes and ranches south of Patagonia and the southern portion of the town of Patagonia. There is no power feed into the SRV by Sulphur Springs Co-Op.

One large ranch lost a deep well pump (burned out) = $3500, a Bose Stereo unit = $2500, a Motorola Analyzer (repaired) = $1500, and a washing machine = $500. They also sustained significant data loss from multiple computers.

Another ranch must replace two electric ovens (no cost estimate yet), ice maker in a Sub-Zero refrigerator replaced for a second time this year, necessity to purchase two generators to run well pumps to water livestock, replacement of power supplies on two computers, each for the second time this year, and a necessity to purchase line conditioners for computers.

There are continuing power surges and brownouts occurring on a daily basis.

During the summer of 2006, lightning struck a pole on the San Antonio Ranch. The arrestor on my pole blew and all customers sustained some damage when the power was restored. However, it took Unisource 4 weeks (during the monsoon season) to replace my arrestor, despite multiple phone calls to their Nogales office. Only when I said that I was sending letters to Unisource, and I inquired about administrator names and addresses, did they immediately come out to replace the equipment.

They certainly responded that same day before I could mail the letters.

Everyone on this line has experienced the same hours of power outage as documented on the LED readout of the integral computer in the control panel of my Cummins 35 kW standby generator: since June 16, 2005, at 10:30AM (date and time that generator was placed online) I have experienced 228 Engine hours and 19453 Control hours. These LED readings were confirmed by the Power Division of Cummins Rocky Mountain Southwest, LLC. This generator is on a weekly 20 minute exercise period, so this would result in an exercise hour total of 38.6 hours since June 16, 2007.

Therefore, since June 16, 2005: SRV line power outage = 189 hours (228 hours - 39 hours = 189).

Some SRV customers have been out of power for longer total periods due to equipment failure at their installations.

My primary power is from a single-phase line that originates from the San Rafael Valley 3-phase line crossing the head of Goldbaum Canyon. I have been told that my single phase "primary power voltage is 7620 V."

Documentation of wide swings in my home/vineyard voltage was made by Wilson Electric - Tucson. Conversations between Wilson Electric and Unisource resulted in my voltage returning to a more normal state in 2006. (Discussion of this is in a prior email to you).

Also refer to recent article in The Weekly Bulletin. (previously
forwarded to you)

DISCUSSION:

These facts cover mainly the last two major power outages (August / September, 2007) that lasted a total of 45 hours. Obviously, the list of damaged equipment is more extensive when considering previous years. When I moved here in 2002, we were still under Citizens Utility service and I recorded 60 hours of power outage for the year of June 2002, to June 2003. Things have not improved with Unisource. Because of this initial experience, I had to include a permanent standby generator during construction (2004 - 2005) of our new home complex and to run the frost protection spray system in my vineyard.

Unisource line crew members say that "all" of the problems are due to lightning, but that is not so. Unisource receptionists and office staff will never say what causes power outages. We have power surges, brownouts, and power outages when the skies are clear. In the winter when we have days of rain WITHOUT lightning, we still have power outages. Electricians have told me that Unisource is maintaining a higher than normal voltage on the line to "pump" more electricity into Santa Cruz, Mexico. We fully understand that weather can result in downed poles and lines, but it seems unlikely that all of our problems are always due to this. We suspect that faulty equipment is also to blame. It is well known that Citizens Utility did not have state of the art equipment in place when Unisource bought the system. I was born and raised in Kingman, Arizona, and I am well aware of the terrible reputation that Citizens had during its business years in Arizona.

Anecdotal information regarding the Willow fire in the San Rafael Valley in the summer of 2006 directs the cause of the fire as being due to "failure of Unisource equipment on a pole" and melted equipment fragments landing in the grass with subsequent ignition.

Originally, the blame was laid on "illegal immigrants failing to extinguish a campfire". The U.S. Forest Service has never filed an official document stating the cause of the fire, but anecdotal accounts of the conversations between SRV residents and Forest Service fire investigators result in a silent finger pointing to failure of a Unisource fuse on a pole.

Just before the Willow Fire was discovered, three ranches on an underground power line sustained an outage. Unofficial findings noted a source of ignition with accompanying fuse fragments beneath the pole from which the transition is made from the overhead to the underground line. This pole was not burnt to suggest that the fire affected the fuse, rather, it was the reverse. Unisource replaced the fuse and it immediately blew. Then they realized there was a break in the undergound line, and by the time it was repaired, the ranches had been without power for three days. The installation (1960's) of this underground line was paid for by Mr. Larry Robbins of the Little Outfit Ranch and allows for a gorgeous unobstructed view of the northern end of the San Rafael Valley. Ranchers have said that Unisource refuses to replace this aging line as there "is an insufficient number of clients receiving power from the line."

QUESTIONS:

Why is it that Unisource will never divulge information to its customers? During power outages, the only admission made by the receptionists will be the number of customers affected, which will range from "130 to 300."

What type of system do we have supplying power to the SRV? From which Unisource substation does it originate?

Does the federal government or the AZ Corporation Commission hold Unisource to different standards - is there one quality standard for supply to urban customers and another quality standard to rural folk?

Is it one line supplying all of the Valley to include Harshaw,
Washington Camp, Duquesne, Lochiel and the new AZ State Park (the former Sharp Ranch) and Santa Cruz, Sonora? We understand that one line comes to us through Flux Canyon from a "Rio Rico substation." Is there another line coming up Sycamore Canyon from Nogales to Washington Camp/Duquesne?

Can we petition Sulphur Springs Co-Op to take over this line and
supply our power? Would Sulphur Springs be interested?

Can a loop be established between Sulphur Springs and Unisource to provide a backup power supply if one or the other side fails?

How much power is being consumed in Santa Cruz, Mexico? Does
Unisource even know the number of customers tapped into the system?

Do they sell power to a Mexican subsidiary or does Unisource bill the individual Mexican customer? Does the fact that there is
international distribution of power place more specific regulation on
a power company with this international commitment? Is there an
overload consumption problem on the Mexican side?

Are the brownout problems in the SRV due to Unisource power generation and distribution failures or are the brownouts due to unregulated excessive consumption at the end of the line in Mexico?

How do we solve the problem?

You can be assured that the San Rafael Valley Assn. will participate
in your Santa Cruz County Citizen's Advisory Committee, and I will be forwarding documentation of our problems to you for review and comment before I file these with the Corporation Commission. We truly appreciate your guidance.

Thank you very much for your consideration and kindness.

Jon......

Jon B. Coppa, MD
President - San Rafael Valley Association
Venado Cola Blanca Vineyard, Inc.
P.O. Box 517
785 San Rafael Valley Road
Patagonia, AZ 85624

phone: (520) 394-0239
fax: (520) 394-0238

EXHIBIT
M-28
Admitted

UNS ELECTRIC, INC.'S RESPONSE TO
MR. MAGRUDER'S FIRST SET OF DATA REQUESTS
DOCKET NO. E-04204A-06-0783
May 7, 2007

MM DR 1.8 Do any of the UNS entities anticipate holding public meetings with their customers, school boards, county supervisors, city and town councils, chambers of commerce, builder's organizations, unions, industry groups, and other civic organizations to inform them and public officials about how these proposed rate charges will impact their new electricity bills?

a. If so, please provide the schedule and agenda for these meetings.
b. If such meetings have already been held, please provide copies of any handouts, newspaper clippings, and news releases.
c. In particular, which of these public entities has UNS Electricity discussed the proposed Time of Use (TOU) and PPFAC changes since submission of the UNSE 15 December 2006 Application?
d. Please provide a copy of ALL customer comments (positive, negative and/or neutral) received by any UniSource entity concerning this rate case since 15 December 2006.

RESPONSE:

a. UNS Electric has not held any public meetings regarding the filing.

b. Meetings were held individually with Mohave County Supervisors from all three districts and the County Manager. UNS Electric also met with the Mayor and City Manager from Kingman and Lake Havasu. Please see MM DR 1.8 (b) (Rate Case at a Glance), Bates Nos. UNSE(0783)03573, on the enclosed CD for a copy of the handout that was provided. The Mohave County Coalition of Chambers of Commerce was also presented with a summary of the filing. Please see MM DR 1.8 (b) (Press Release), Bates Nos. UNSE(0783)03574 to UNSE(0783)03575, on the enclosed CD for the press release regarding the UNS Electric filing that was sent to Santa Cruz County Manager and Nogales City Manager.

c. The TOU provision was only mentioned generally as an incentive for customers to shift load off of UNS Electric's peak load times. The Purchase Power and Fuel Adjuster Clause was not discussed.

d. The Company did not capture comments made at these informal meetings.

RESPONDENT: Thomas Ferry and Tom Hoyt

WITNESS: Thomas Ferry

UniSource Energy Services Electric Rate Proposal At-A-Glance

Basic Information

- The proposed rates would result in a 4.4-percent increase for average residential customers in Mohave County while producing an average 0.6 percent *decrease* for their peers in Santa Cruz County. Residents and smaller business customers in Santa Cruz County have historically paid more than their peers in Mohave County, and UES is proposing a unified rate structure. Changes for other customers vary (see table).
- If the Arizona Corporation Commission (ACC) follows a typical 13-month calendar for such matters, the changes could take effect in spring of 2008.
- The proposed rates would cover the cost of a new 90MW generating facility in Mohave County to help meet peak loads in the fast-growing region. They also include a revised Purchased Power and Fuel Adjustment Charge (PPFAC) to recover energy costs after the current supply contract with Pinnacle West expires in June 2008.
- The rates would allow UES to expand its Energy Smart Homes program, provide new resources for low-income weatherization and fund other energy efficiency programs.
- The proposal would result in the first rate adjustment since August 2003, and the first general rate increase since January 1997.

Increase (or Decrease) in Average Bills in Mohave, Santa Cruz territories*

Customer Class	Mohave	Santa Cruz	Avg kWh/month
Residential	4.4%	(0.6%)	863 **
Small General Service	18.5%	(17.2%)	1,012
Large General Service	5.7%	5.7%	20,215
Large General Service TOU	5.5%	5.5%	24,198
Interruptible Power Service	4.0%	4.0%	74,889

* The impact of changes to Large Power Service rates, which apply to just 11 customers, are highly dependent on individual customer characteristics, so an average is not useful. If the proposed changes had been in place during the test year used in this rate case, UNS Electric would have received a 5.9 percent increase in revenue from those customers.

** Average residential usage is 898 kWh/mo. in Mohave and 718 kWh/mo. in Santa Cruz.

Reasons Behind the Rates

- The new rates will help UES cover the costs of serving customers' growing needs. The company's customer base is expanding by about 5 percent a year, compared to the 2.5 percent annual growth rate of its sister company, Tucson Electric Power.
- UNS Electric's customer count has increased 61 percent (from 57,000 to 92,000) since March 1995, the end of the test year used in Citizens' last general rate case.
- Since UES took over for Citizens in August 2003, the company has invested more than $74 million in infrastructure improvements to serve rising customer demand. Operating costs, meanwhile, have more than doubled since the last general rate case. These costs are not reflected in the company's current rates.
- When UES power supply contract expires in June 2008, the company will have to buy energy for customers at higher market prices. UES already has begun securing contracts and has proposed acquiring two planned 45-MW gas turbines in Mohave County.

New Rate Design

- For residential customers, the new rates include a higher monthly customer charge – $8 per month, up from $6.50 – to cover increased infrastructure costs. A staggered energy charge would set a lower price for the first 400 kWh used, encouraging conservation.
- New time-of-use rates, available to all and automatic for new customers, would allow lower average rates for those who shift usage away from peak periods.
- A flat $8/month CARES discount for low-income customers would replace the existing usage-based discount, encourage conservation.
- New Warm Spirit program will raise contributions for a fund to help local agencies provide emergency bill payment assistance to low-income customers. UES will provide up to $25,000 per year to match customer contributions to the program.

UniSourceEnergy SERVICES NEWS

FOR IMMEDIATE RELEASE
News Media Contact: Joe Salkowski, (520) 884-3625
Investor Contact: Jo Smith, (520) 884-3650

December 15, 2006

UES PROPOSES NEW RATES TO COVER RISING COST OF ELECTRIC SERVICE;

Tucson, Ariz. – UniSource Energy Services (UES) has asked the Arizona Corporation Commission (ACC) to approve new, more equitable electric rates to cover the rising expense of serving some of the state's fastest growing communities.

"We've invested more than $74 million over the past three years to strengthen and expand our electric distribution system, and our operating costs have more than doubled since the last full rate case," said James S. Pignatelli, Chairman, President and CEO of UES' parent company, UniSource Energy Corporation (NYSE: UNS).

"Those additional costs are not reflected in our current rates," Pignatelli said. "We're going to need those resources so we can continue to expand our system in a way that supports the dramatic growth we're seeing in Santa Cruz and Mohave Counties."

UES' customer base has been growing at an annual rate of nearly 5 percent. The industry's average customer growth rate is 1.5 percent, while the customer base of UES' sister company, Tucson Electric Power, is expanding by 2.5 percent per year.

The proposed rates would cover the costs of serving that growth while eliminating an imbalanced rate structure UES inherited when UniSource Energy acquired the system from Citizens Communications (NYSE: CZN) in August 2003. Under that structure, which was based on outdated cost of service data, some Santa Cruz County customers pay higher rates than their peers in Mohave County.

The new, unified rate for residential customers would result in an increase of 4.4 percent – about $4 per month – for average residential customers in Mohave County. In Santa Cruz County, the new rate would reduce the average resident's bills by 0.6 percent – about $0.46 per month.

The new rates also would eliminate a wider disparity in energy costs paid by small businesses. UES' proposal would increase the average bills of those customers in Mohave County by 18.5 percent – about $19 per month – while reducing them by 17 percent – about $25.50 per month – in Santa Cruz County. Rates for larger commercial customers, which do not differ between the counties, would increase by an average of 4 to 6 percent under the company's proposal.

UES' request to resolve the rate disparity between Mohave and Santa Cruz Counties continues a similar effort mounted by Citizens in its two most recent rate proceedings. In each of those cases, the ACC expressed its support for consolidated rates.

If the ACC follows its typical 13-month calendar for such matters, the new rates could take effect in the spring of 2008. Current rates are frozen through at least August 2007.

Any approved increase would be the first general rate increase for UES electric customers since January 1997. Although the ACC increased a power supply charge when UES took over the system in August 2003, that fee does not compensate the company for the rising costs associated with delivering that power to customers.

The proposed increases in Mohave County coincide with the need to develop new sources of power for those northern Arizona customers. While UES already owns 65 MW of generating capacity in Santa Cruz County to help serve nearly 20,000 customers in that southern Arizona region, the company relies solely on purchased power to serve more than 72,000 Mohave County customers.

The proposed rates make provisions for the new power sources that will be needed after UES' current supply contract expires in June 2008. The company has already begun securing new supply contracts and has proposed acquiring two 45-MW gas turbines being built in Mohave County by a sister company, UniSource Energy Development.

UES also has proposed new time-of-use rates that would be available to all customers and automatic for new customers. The rates, which charge more for power used at peak periods and less for off-peak usage, would allow lower average rates for customers who shift their consumption away from peak load periods.

The proposed rates include new benefits for qualified low-income customers. An expanded CARES program would replace the current usage-based subsidy with a flat $8 per month discount for qualified applicants. Customers also would be invited to help local agencies provide emergency bill payment assistance through a new Warm Spirit program. As it does with a similar program for its natural gas customers, UES would provide up to $25,000 per year to match customer contributions.

The new rates also would allow UES to enhance its energy conservation offerings. The company has proposed expanding its Energy Smart Homes, which helps local builders offer energy efficient homes to buyers. UES also has offered to make more resources available to help low-income customers make their own homes more efficient.

UniSource Energy Services, a subsidiary of UniSource Energy, provides electric service to more than 92,000 customers in Mohave and Santa Cruz Counties. It also provides natural gas service to more than 142,000 customers in Mohave, Yavapai, Coconino, Navajo and Santa Cruz Counties. For more information about UniSource Energy Services, visit www.uesaz.com. For more information about its parent company, UniSource Energy, visit www.uns.com.